Generator Interconnection Study:

Delaware Public Service Commission Study of Generation Alternatives in Delmarva Power and Light

Author:	PowerWorld Corporation Kollin Patten
Client:	Delaware Public Service Commission
Subject:	Contingency Evaluation of Four Generation Alternatives in DP&L
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PowerWorld Corporation

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Background and Objective

Delaware Public Service Commission (Commission) has contracted with PowerWorld Corporation (PowerWorld) to review the system reliability of the Delmarva Zone in the 2013 time frame for four generation alternatives located within the Delmarva Zone. This study consists of the modification of a summer peak load flow case to include the four presented generation alternatives, simulation runs using power transfer distribution factor (PTDF) and contingency analysis, and a compilation and analysis of the simulation results.

Study Assumptions and Limitations

The study is based on available information in NERC MMWG power flow cases. The most recent available MMWG filings are from 2006, with summer peak representations of 2007, 2011 and 2016. Given a 2013 representative case was not immediately available, the 2011 summer peak case was selected for this project.

A cursory review of the 2011 case identified that many of the PJM transmission expansion projects currently under construction or study by PJM have been modeled in the 2011 summer peak case, although the extent and exact listing of included projects is not known. The Commission identified only one specific PJM transmission project of concern, that being the Mid-Atlantic Power Pathway project. The Commission requested that the base case be examined for the inclusion of the project, and that it be removed from service in the base case if included. As it turns out, the final phases of the Mid-Atlantic Power Pathway project are not scheduled for completion until 2014. The examination of the 2011 base case revealed that none of the stages of the project were included, and therefore no case modification was necessary regarding this project.

Additionally, the Commission also requested that the Indian River units 1 and 2 be removed from service for the analysis, as there is the potential for retirement of the units as early as January of 2009. The units were removed from service in the 2011 summer peak base case, and the base case was re-solved with the power redistributed to the remaining DP&L existing generation. The impact on the base case steady state voltage from the retirement was minimal. Examination of the base case showed that these two units were injecting a total of only 9 MVAR in the base case prior to retirement, and that the largest decrease in base case steady state voltage anywhere in DP&L from the retirement of the units was only 0.5kV at the Cartanza 230kV bus. However, the retirement of these units could have a larger impact on steady state voltage in certain contingency scenarios, most notably an outage of the Indian River 4 unit. The loss of Indian River 4 by itself resulted in some voltage drop in the surrounding system, but the remaining Indian River units and the Indian River SVC were able to keep the largest voltage drop to 2.5kV on the Cartanza 230kV bus. However, considering the Indian River 1 and 2 retirements in addition to the Indian River 4 outage resulted in a more significant voltage reduction of 6.75kV at the Milford 230kV bus, and resulted in the Indian River SVC being maxed out at 150 MVAR. This indicates that steady state voltage in the region may be more stressed under contingency if the Indian River 1 and 2 units are retired without a replacement VAR source.

Each of the four generation alternatives were added to the 2011 summer peak load flow case with some general modeling assumptions. Each alternative was connected to the high voltage transmission grid at the proposed step-up point on the grid. Lower voltage generator terminal or collector system equipment were assumed implicitly modeled with each of the new generator models, and assumed adequate for delivering the power to the high voltage grid interconnection points. In addition, it was also assumed that sufficient voltage support for each of the generation alternatives was available. In the case of the wind farm alternative, typically the VAR support comes in the form of additional devices, such as capacitor banks or dynamic VAR devices. This study will treat the VAR output of the wind farm alternative as sufficiently available, without any interpretation as to specifically what kind of devices are required for delivering the VARs.

Power output from each of the new alternatives was independently evaluated using two generation displacement assumptions. The first displacement assumption distributed the new injection from a generation alternative to all on-line generators in DP&L, in proportion to the capacity of each generator (Appendix A.) The second displacement assumption offset the scheduled power imports into DP&L, with the generators in the rest of PJM (excluding Exelon, i.e. Commonwealth Edison) decreasing output in proportion to their capacity to maintain the system power balance. Under both generation offset assumptions, the loads were held constant throughout the case.

The PowerWorld Simulator 12.0 software developed by PowerWorld Corporation was used to perform the simulations in this study. Within the software, the PTDF and contingency analysis tools were used for the specific calculations in the study. The PTDF tool uses linear sensitivities to estimate the amount of each new injection that would appear on each transmission element. This is useful for identifying the transmission elements that will be significantly affected by the new injection. The contingency analysis tool determines how an outage of a transmission element will affect the rest of the transmission elements in the region, and specifically identifies elements that violate their thermal or voltage ratings as a result of the contingent outage.

For the contingency analysis study, all non-radial transmission elements in DP&L rated at 69kV and higher were monitored for overloads. At lower voltages and on radial facilities, it was assumed that local actions could relieve transmission congestion. Thermal transmission ratings were taken directly from the 2011 summer peak case without modification. For the contingency analysis, the long-term contingency ratings represented in the case were used for reporting violations under contingency.

The contingencies defined for the analysis included all n-1 contingencies of DP&L transmission lines at 100kV and above, and all DP&L transformers with a low-side voltage of 69kV and above. It is likely that DP&L has remedial action schemes in place for certain regional contingencies, including some n-1 contingencies modeled here. The contingency analysis in this study examines the overloads caused by the n-1 contingencies without any remedial action consideration, to see the base impact of a transmission outage on the remaining elements in DP&L. In addition to the n-1 contingencies modeled in DP&L, an additional contingency was also included for each generation alternative scenario, representing the generation outage of the new generation while at full output. This contingency considers the sudden loss of the new generation, made up by all other generation in the case for the sudden loss, and assumes voltage controlling devices such as tap-changing transformers and switched shunts do not immediately respond to the outage.

Base Case Contingency Analysis

Prior to running the contingency analysis on each of the generation alternative scenarios, a base case contingency analysis was performed to identify any base case contingent violations. These base case violations are used to compare against the results of the contingencies from each generation alternative. Table 1 below displays the base case branch thermal violations observed, while Table 2 displays the base case voltage violations.

Table 1 - Base Case Contingency Violations

Base Case Branch Thermal Violations			
Overloaded Element	**Limit**	**Contingency Element**	**Percent**
GLASGOW (8818) -> CECIL138 (9388) CKT 1 (138kV)	79.00	CECIL (9385) to COLOR_PE (9386) CKT 1 (230kV)	116.11
		CECIL3 (9390) to CECIL (9385) CKT 1 (345.5/230kV)	116.11
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 1 (230/138kV)	478.00	INDRV2&3 (9176) to INDRIV4 (9171) CKT 2 (138/230kV)	111.64
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 2 (230/138kV)	531.00	INDRV2&3 (9176) to INDRIV4 (9171) CKT 1 (138/230kV)	100.50
INDRV2&3 (9176) -> OMAR (9182) CKT 1 (138kV)	336.00	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	108.52
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	117.74
LORETTO (9262) -> LORET_69 (9277) CKT 1 (138/69kV)	66.00	LORET_69 (9277) to LORETTO (9262) CKT 2 (69/138kV)	114.37
LORETTO (9262) -> LORET_69 (9277) CKT 2 (138/69kV)	64.00	LORET_69 (9277) to LORETTO (9262) CKT 1 (69/138kV)	112.89
		PINEY_69 (9285) to PINEY138 (9264) CKT 1 (69/138kV)	100.53
OMAR (9182) -> BETHANY (9173) CKT 1 (138kV)	336.00	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	101.40
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	109.49
WORCR_69 (9210) -> BERLINTP (9186) CKT 1 (69kV)	95.00	OCNBAY (9203) to OCEANBAY (9177) CKT 1 (69/138kV)	103.17

Table 2 - Base Case Contingency Voltage Violations

Base Case Bus Voltage Violations			
Voltage Violating Bus	**Limit**	**Contingency Element**	**PU Voltage**
FIVE PTS (9193) (69kV)	0.9000	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8937
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	0.8982
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8863
		IR4 (9219) to INDRIV4 (9171) CKT 1 (26/230kV)	0.8999
LEWES TP (9197) (69kV)	0.9000	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8997
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8924
MIDWAY (9200) (69kV)	0.9000	INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8990

In all contingency analysis scenarios, a total of 296 branches and transformers were monitored in DP&L for potential thermal violations. Under normal pre-contingent system conditions represented in the 2011 summer peak base case, none of the 296 monitored elements were violating either their normal or long term emergency ratings. The contingency results show thermal overloads on eight different transmission elements. Four of the eight violating elements experienced overloads under more than one contingency scenario. The most severe base case contingency overload of 117.74% occurred on the Indian River to Omar 138kV transmission line, under the contingency outage of the Indian River to Frankford 138kV branch.

In addition to the eight contingency thermal violations, there were also three buses that experienced low voltage violations under contingency as well. All three of these buses were 69kV buses, two of which experienced low voltage under two or more contingency scenarios. The lowest voltage experienced under contingency was 0.8863 per unit at the Five Points 69kV bus during the Indian River to Frankford 138kV contingency outage. This is the same contingency outage that also caused the highest thermal overload as well.

Another important finding from the base case contingency analysis was the existence of five contingencies that resulted in a failed load flow solution, listed in Table 3.

Table 3 - Base Case Unsolvable Contingencies

Unsolvable Contingencies
INDRIV 1 (9195) to INDRV2&3 (9176) CKT 1 (69/138kV)
INDRV2&3 (9176) to ROBINSON (9181) CKT 1 (138kV)
REHOBOTH (9178) to ROBINSON (9181) CKT 1 (138kV)
REHOB_69 (9207) to REHOBOTH (9178) CKT 1 (69/138kV)
BETH_69 (9188) to BETHANY (9173) CKT 1 (69/138kV)

These five contingencies are all related to paths from the Indian River 138kV and Bethany 138kV down to the underlying 69kV system in the area. A general representation of these connections is shown in Figure 1.

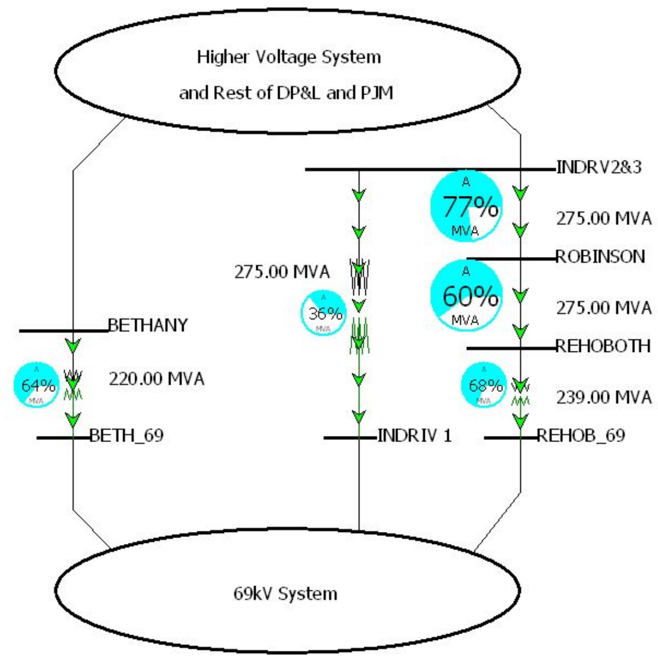

Figure 1 - 138kV to 69kV Connections at Indian River and Bethany

These three connections are the only high voltage pathways into the underlying 69kV system, meaning that if a contingency occurs on any one of the three paths, the other two paths will have to carry the full load of the 69kV system demand. When any one of the three paths is open, the voltage in the 69kV load pocket drops significantly, causing some of the lower voltage 69kV elements in the pocket difficulty in delivering the needed power at low voltage levels. It is assumed that realistic operation of the system would result in dropping of load in this load pocket if one of these five contingencies actually occurred. In this analysis, it was observed that the same five contingencies were unsolvable for all four alternatives studied. Assuming that other unknown remedial actions would take place if one of these five contingencies actually occurred, these five contingencies are not included in the comparison details of each alternative analysis to the base case contingency analysis.

Alternative 1: 600 MW Wind Farm Connected at Bethany Substation

Interconnection of the proposed 600 MW offshore wind farm was detailed to occur through four 138kV submarine cable circuits at either the 138kV Rehoboth bus or the 138kV Bethany bus in DP&L. Discussions with Commission staff led to focusing the analysis at the Bethany 138kV interconnection point for this analysis.

Load Flow Model Representation

The interconnection was modeled with a new generator at the existing Bethany 138kV substation. The generation was set to 600 MW directly into the Bethany 138kV bus. The voltage support of the new generation was given a large range of operation under the assumption that ample VAR support would be available. The voltage regulation of the new generator was set to 1.04 per unit voltage of the Bethany 138kV terminal bus. The voltage regulation value was determined by examining regulation voltage settings of other generators and voltage controlling devices in the vicinity of the Bethany substation. Figure 2 and Figure 3 illustrate the proposed electrical connection.

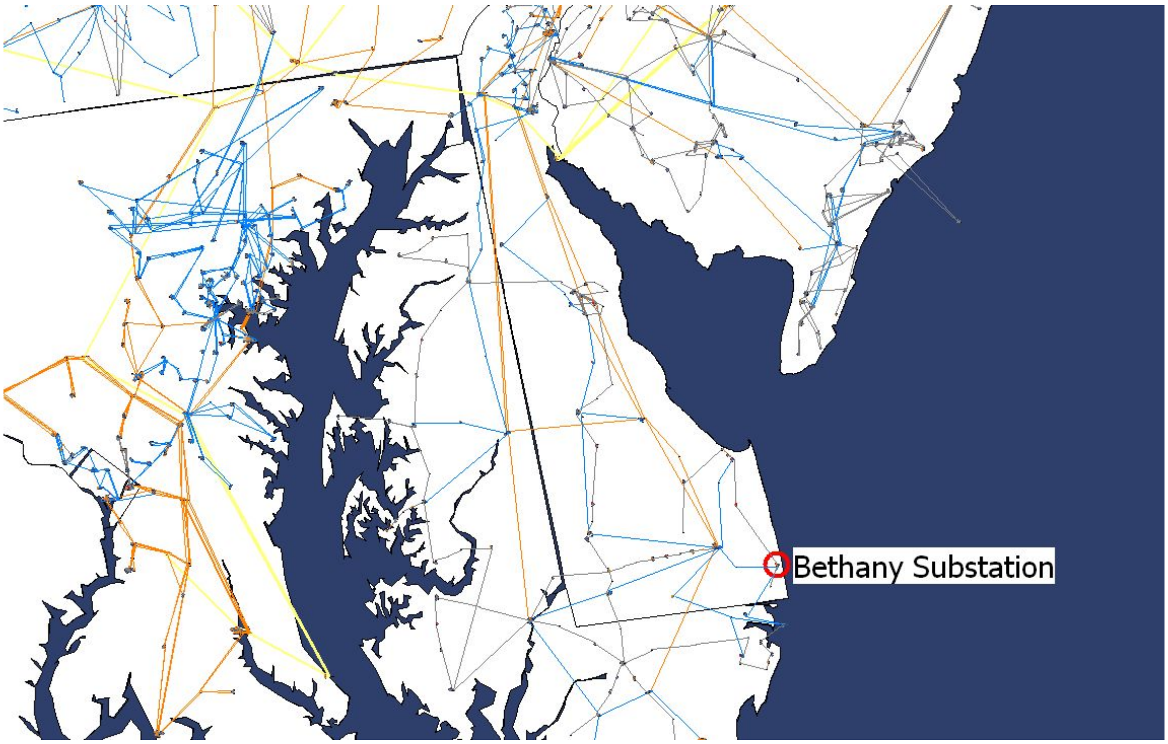

Figure 2 – Bethany Substation Location

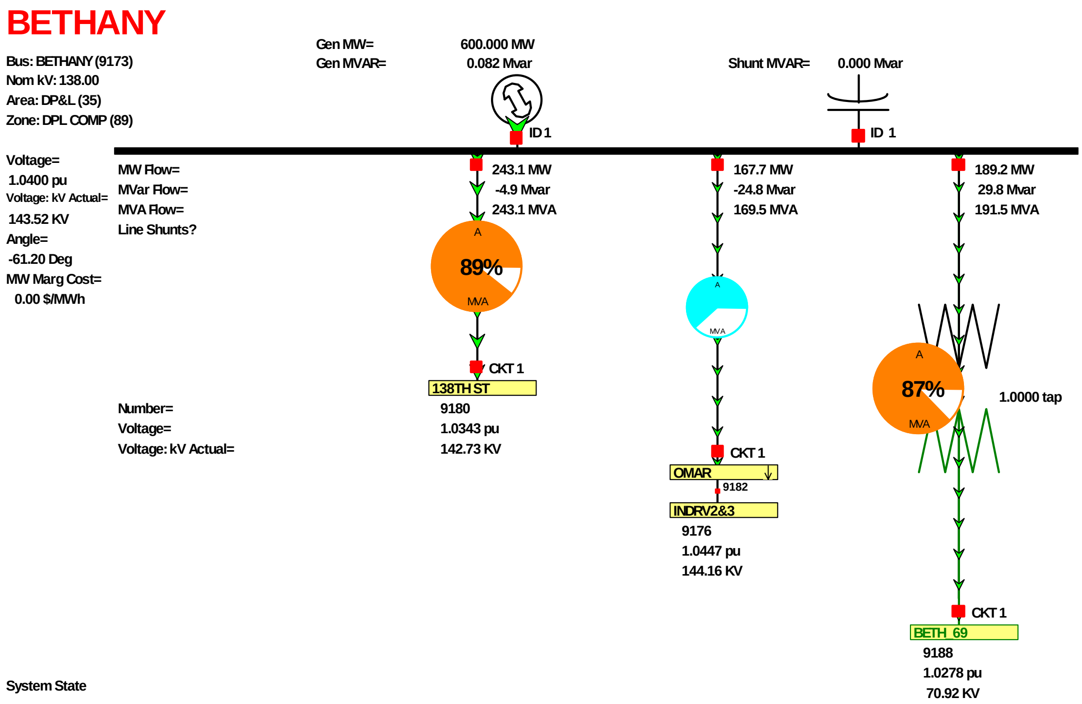

Figure 3 – Bethany 138kV Bus, Showing New Generation and Load Flows

Two different scenarios of generation offset were considered for the new injection at Bethany. The first involved the DP&L generation re-dispatching to accommodate the new injection, and the second involved reducing the DP&L imports and forcing other PJM generation outside of DP&L to re-dispatch to maintain the system power balance. PTDF contours of each generation re-dispatch scenario (shown in Figure 4 and Figure 5) show the lines most impacted by the shift in power flow from the new injection. Lines that carry more than 25% of the injected power are highlighted in yellow to red. Lines carrying between 10% and 25% are colored in light to dark green. Any transmission elements carrying less than 10% of the injected power are not highlighted. The PTDF contour does not indicate whether the additional flow is increasing or decreasing the total flow on each element.

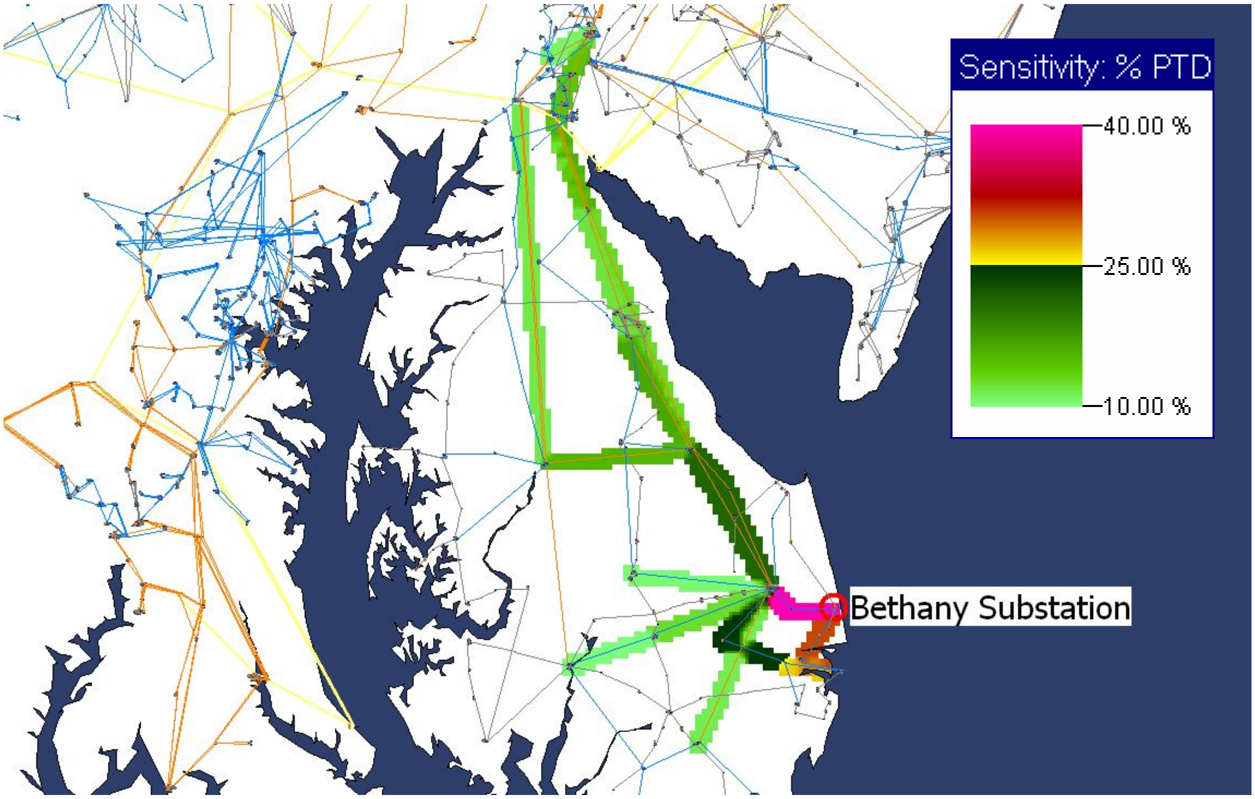

Figure 4 - Bethany Substation PTDF Contour, with Re-dispatch of DP&L Generation

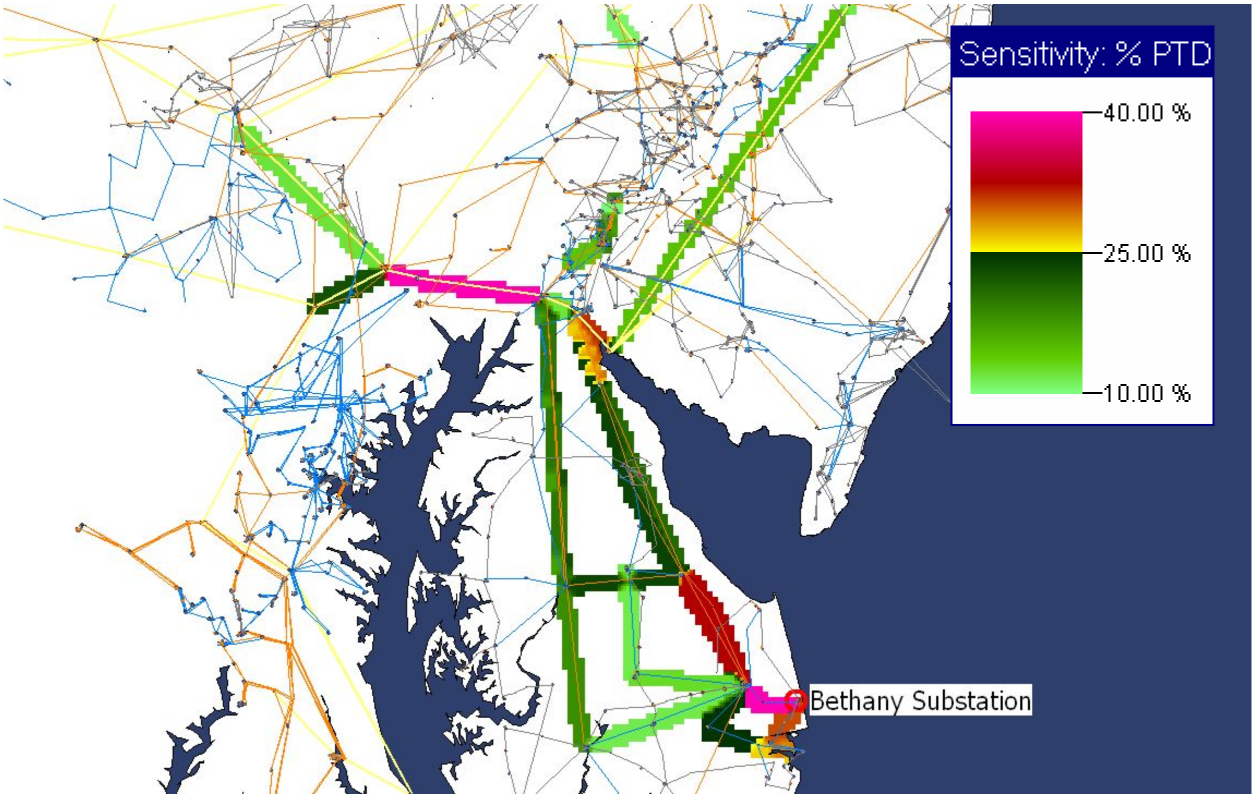

Figure 5 - Bethany Substation PTDF Contour, with Re-dispatch of PJM Generation

Contingency Analysis

Prior to running the contingency analysis, the 600 MW wind farm injection was dispatched at the Bethany 138kV bus, once with the DP&L generation as the sink for the new generation and once with the DP&L imports reducing to offset the new generation. The monitored elements in DP&L were assessed for pre-contingent violations, with no thermal or voltage violations on the DP&L monitored elements observed.

The contingency analysis was then run twice for the 600 MW wind farm connection at Bethany, once each for each sink scenario defined. The results of both contingency runs have been compiled in Table 4 and Table 5 to compare with the original base case contingency violations.

Table 4 - Contingency Thermal Violations for 600 MW Wind Farm Injection at Bethany

Bethany Injection of 600 MW Wind Farm (Alternative 1)			**Percent Overload**		
Overloaded Element	**Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
BETHANY (9173) -> 138TH ST (9180) CKT 1 (138kV)	348	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)		107.63	107.56
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)		104.17	104.10
BETHANY (9173) -> OMAR (9182) CKT 1 (138kV)	336	BETHANY (9173) to 138TH ST (9180) CKT 1 (138kV)		113.91	113.90
		OCEANBAY (9177) to 138TH ST (9180) CKT		101.49	101.48

		1 (138kV)			
GLASGOW (8818) -> CECIL138 (9388) CKT 1 (138kV)	79	CECIL (9385) to COLOR_PE (9386) CKT 1 (230kV)	116.11	116.09	116.09
		CECIL3 (9390) to CECIL (9385) CKT 1 (345.5/230kV)	116.11	116.09	116.09
		CONOWG01 (4066) to COLOR_PE (9386) CKT 1 (230kV)			104.80
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 1 (230/138kV)	478	INDRV2&3 (9176) to INDRIV4 (9171) CKT 2 (138/230kV)	111.64		
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 2 (230/138kV)	531	INDRV2&3 (9176) to INDRIV4 (9171) CKT 1 (138/230kV)	100.50		
INDRV2&3 (9176) -> OMAR (9182) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	108.52		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	117.74		
LORETTO (9262) -> LORET_69 (9277) CKT 1 (138/69kV)	66	LORET_69 (9277) to LORETTO (9262) CKT 2 (69/138kV)	114.37		104.54
LORETTO (9262) -> LORET_69 (9277) CKT 2 (138/69kV)	64	LORET_69 (9277) to LORETTO (9262) CKT 1 (69/138kV)	112.89		103.19
MARIDEL (9199) -> OCEANCTY (9204) CKT 1 (69kV)	116	BISHOP (9174) to WORCESTR (9179) CKT 1 (138kV)		105.14	103.85
		WORCR_69 (9210) to WORCESTR (9179) CKT 1 (69/138kV)		105.15	103.86
OAKHL_69 (9330) -> WATTSVIL (9333) CKT 1 (69kV)	91	PINEY_69 (9285) to PINEY138 (9264) CKT 1 (69/138kV)	100.53		
OCEANCTY (9204) -> CULVER (9191) CKT 1 (69kV)	93	BISHOP (9174) to WORCESTR (9179) CKT 1 (138kV)		100.13	
		WORCR_69 (9210) to WORCESTR (9179) CKT 1 (69/138kV)		100.13	
OCNBAY (9203) -> MARIDEL (9199) CKT 1 (69kV)	137	BISHOP (9174) to WORCESTR (9179) CKT 1 (138kV)		113.50	112.36
		WORCR_69 (9210) to WORCESTR (9179) CKT 1 (69/138kV)		113.51	112.36
OMAR (9182) -> BETHANY (9173) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	101.40		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	109.49		
OMAR (9182) -> INDRV2&3 (9176) CKT 1 (138kV)	336	BETHANY (9173) to 138TH ST (9180) CKT 1 (138kV)		109.36	109.35
WORCR_69 (9210) -> BERLINTP (9186) CKT 1 (69kV)	95	OCNBAY (9203) to OCEANBAY (9177) CKT 1 (69/138kV)	103.17	102.93	102.94
WORCR_69 (9210) -> OCEANPIN (9205) CKT 1 (69kV)	78	INDRIV4 (9171) to PINEY GR (9257) CKT 1 (230kV)		102.12	
		PINEY138 (9264) to PINEY GR (9257) CKT 1 (138/230kV)		102.12	

Table 5 - Contingency Voltage Violations for 600 MW Wind Farm Injection at Bethany

Bethany Injection of 600 MW Wind Farm (Alternative 1)			**Voltage Violations, per unit**		
Voltage Violating Bus	**Violated Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
CECIL138 (9388) (138kV)	1.1000	GLASGOW (8818) to CECIL138 (9388) CKT 1 (138kV)		1.1246	
FIVE PTS (9193) (69kV)	0.9000	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8937		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	0.8982		
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8863		
		IR4 (9219) to INDRIV4 (9171) CKT 1 (26/230kV)	0.8999		
LEWES TP (9197) (69kV)	0.9000	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8997		
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8924		
MIDWAY (9200) (69kV)	0.9000	INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8990		

The first result to notice from the 600 MW wind farm injection contingency analysis is that several of the base case violations originally observed are no longer present with the new injection at the Bethany 138kV bus. Only thermal contingency violations on the Glasgow to Cecil 138kV branch, the Worcestor to Berlin Tap 69kV branch, and the Loretto 69kV to 138kV transformers were common to the base case and one or both of the wind farm injection scenarios. The overloads that occurred on the two branches were not significantly increased or decreased by the 600 MW Bethany wind farm injection, therefore this injection has little impact on those two circuits. However, the Loretto transformer contingent overloads were decreased by a reasonably significant amount, to the point where the overloads did not occur when dispatching to DP&L generation, and occurred at much lower percentages when dispatching to a reduced DP&L import. In addition, all of the voltage violations evident in the original base case contingency analysis have disappeared with the addition of the wind farm injection at Bethany.

Bethany Injection to DP&L Generation

Despite alleviating several of the base case contingency violations, the wind farm injection at Bethany did create several new contingent violations. A total of seven transmission elements experienced new thermal overloads and one new bus voltage violation was observed during the contingency evaluation with the new Bethany injection offset specifically by DP&L generation. The locations of the contingency overloaded elements are shown in Figure 6, with elements experiencing overloads for one contingency highlighted dark blue, and elements experiencing overloads for two contingencies highlighted slate blue. All contingent overloads occurred on elements electrically close to the Bethany injection point, with the exception of the Glasgow to Cecil 138kV circuit, located much farther to the North.

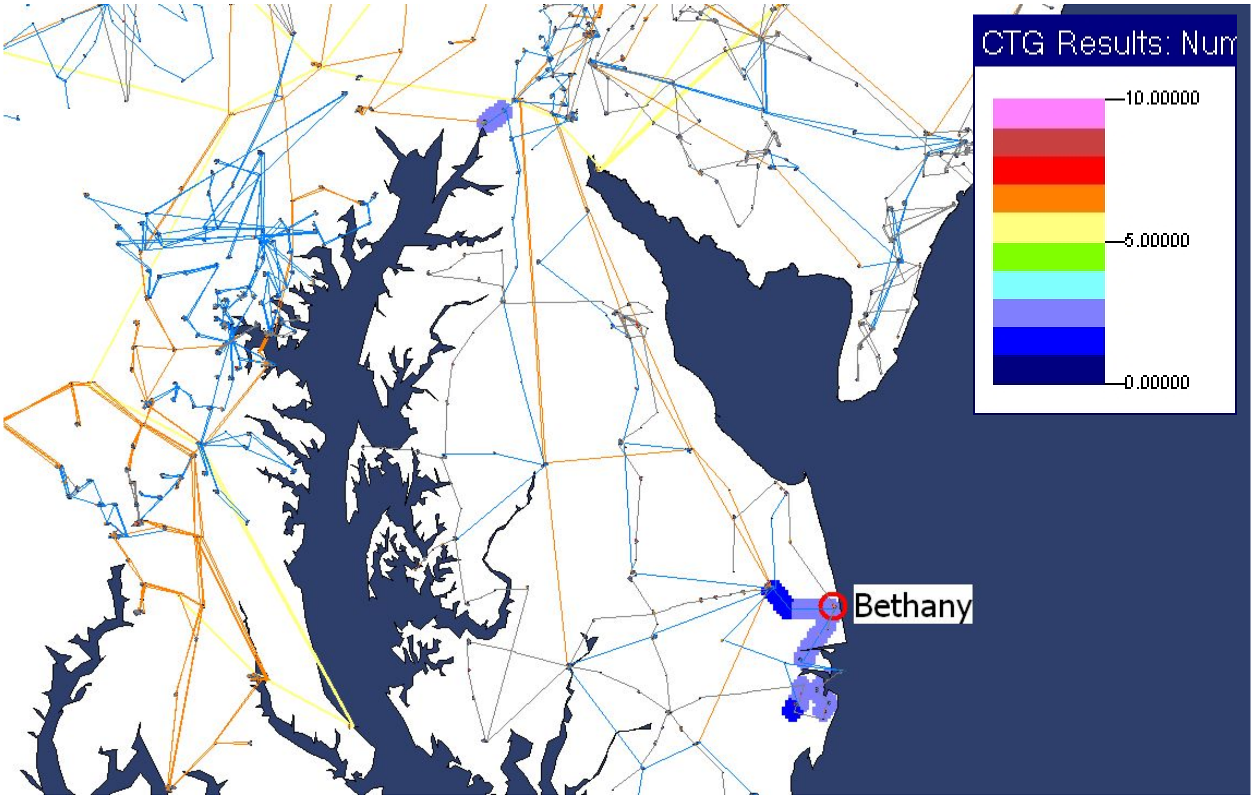

Figure 6 - Highlighting Transmission Elements Experiencing Contingency Overloads – Bethany to DP&L

The largest contingent overload of 116.09% occurs on the Glasgow to Cecil 138kV circuit, but that is nearly identical to the contingent overload on that circuit in the base case results. Thus the Bethany injection has little impact on this overload. The highest new contingent overload due specifically to the new injection at Bethany offset by DP&L generation is 113.91% on the Bethany to Omar 138kV circuit. Two other 138kV circuits experience contingency overloads, those being Bethany to 138th Street and Omar to Indian River. It is possible that circuit upgrades or contingent remedial actions would need to be determined regarding these two circuits for the Bethany injection point, as they will carry a significant amount of the new power injection.

The remaining new contingency violations are on 69kV elements in the nearby 69kV system. Since the 69kV system between Bethany and Indian River has no large-scale connected generation, the new overloads on the 69kV in that region are due strictly to "pass through" of power from the new Bethany 138kV injection. This means that a certain amount of the injected power flows down to the 69kV system at Bethany, and travels across the 69kV network and back out onto the 138kV and 230kV network via connections at Indian River. The contingency violations on the 69kV indicate that circuit upgrades or remedial actions may be necessary with the addition of the 600 MW wind farm injection at Bethany.

The only contingent voltage violation that occurs with the injection of 600 MW at Bethany, offset by DP&L generation, is a high voltage violation at the Cecil 138kV bus during the contingency outage of the Glasgow to Cecil 138kV branch. This high voltage situation may or may not be of serious consequence, and may be handled with remedial actions by DP&L should the contingency occur.

Bethany Injection to DP&L Import Offset

The results of the Bethany wind farm injection offset by reducing DP&L imports are very similar to the DP&L generation offset scenario. There are three transmission elements during the contingency analysis in this scenario that were also contingency overloaded elements in the base case prior to the new injection. There were also five additional transmission elements that experienced contingency overloads under this scenario that were not overloaded in the base case contingency analysis. There are no contingent voltage violations that occur under the DP&L import offset scenario. The locations of the contingency overloaded elements are shown in Figure 7, with elements experiencing overloads for one contingency highlighted dark blue, for two contingencies highlighted slate blue, and for three contingencies highlighted light blue. All contingent overloads occurred on elements electrically close to the Bethany injection point, with the exception of the Glasgow to Cecil 138kV circuit, located much farther to the North.

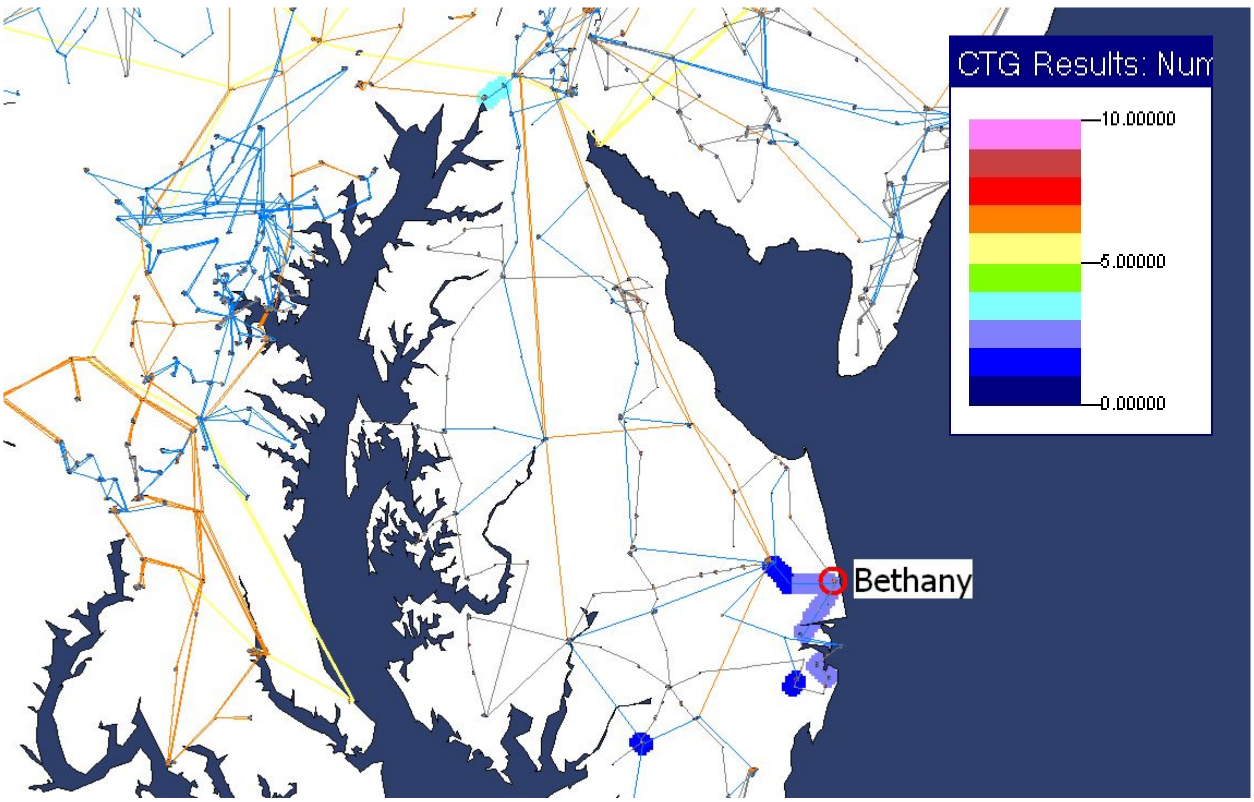

Figure 7 - Highlighting Transmission Elements Experiencing Contingency Overloads - Bethany to PJM

The largest contingent overload of 116.09% occurred again on the Glasgow to Cecil 138kV circuit. Not only is this very similar to the base case contingency violation on this element, but it is also the same overload percentage as in the DP&L generation offset scenario for the Bethany injection. This further enhances the conclusion that the Bethany injection has little impact on this transmission element by also indicating that the sink for the Bethany injection does not change the impact of the Bethany injection on the Glasgow to Cecil circuit.

The highest new contingent overload of 113.90% occurs on the Bethany to Omar 138kV circuit, nearly identical to the DP&L generation offset results. The other two 138kV circuits experiencing contingent overloads are also similarly contingent overloaded in both offset scenarios. This is not unexpected, as the 138kV system out of Bethany will carry a bulk of the new injection whether offsetting DP&L generation or out of area generation.

Summary

The general conclusions from both generation offset scenarios for the 600 MW wind farm at Bethany 138kV substation are that the Bethany injection does help alleviate several base case contingency violations, but at the same time introduces new contingent violations on other circuits. DP&L would need to assess these new violation scenarios more thoroughly, and determine courses of action related to each potential contingent overload. The new Bethany injection does, however, show an improvement of contingent voltage problems with the inclusion of adequate voltage support with the wind farm injection. As previously noted, wind farm voltage support by itself is often limited. For the contingent voltage improvement to be observed as in this analysis, additional voltage support devices would likely be needed in addition to the voltage support capabilities of the wind farm turbines.

Alternative 2: 600 MW IGCC Power Plant at Indian River Substation

The interconnection of the proposed 600 MW IGCC power plant is detailed to occur at the 230kV Indian River substation. This location is electrically very close to the retired Indian River 1 and 2 units, discussed previously in the base case setup.

Load Flow Model Representation

The interconnection was modeled with a new generator at the existing Indian River 230kV substation. The generation was set to 600 MW directly into the Indian River 230kV bus. The voltage support of the new generation was given a large range of operation under the assumption that ample VAR support would be available. The voltage regulation of the new generator was set to 1.04 per unit voltage of the Indian River 230kV terminal bus. The voltage regulation value was determined by examining regulation voltage settings of other generators and voltage controlling devices in the vicinity of the Indian River substation. Figure 8 and Figure 9 illustrate the proposed electrical connection.

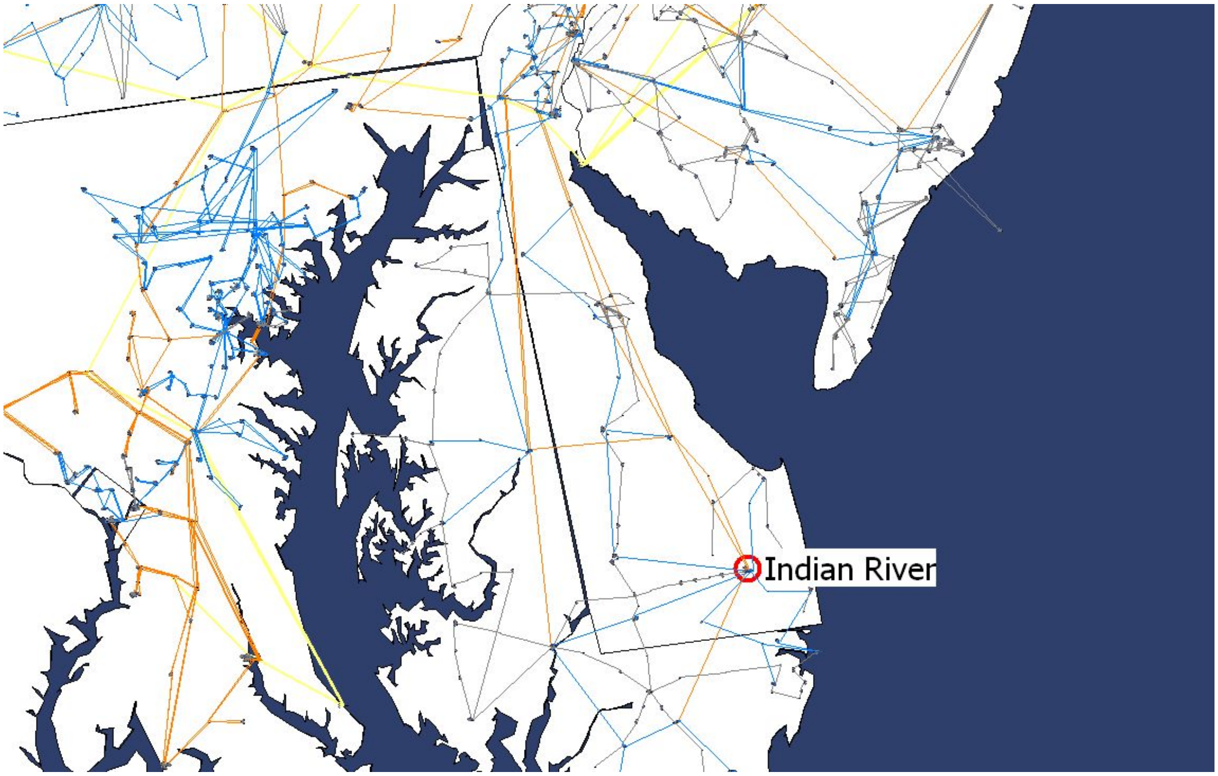

Figure 8 - Indian River Substation Location

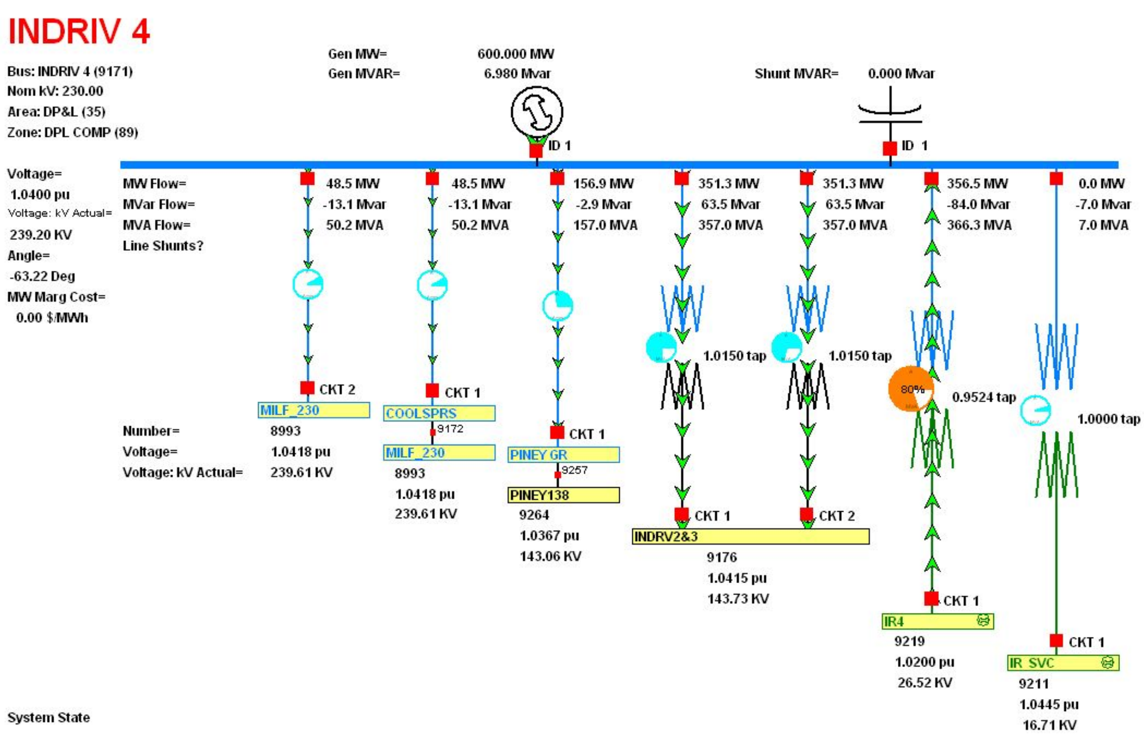

Figure 9 - Indian River 230kV Bus, Showing New Generation and Load Flows

Two different scenarios of generation offset were considered for the new injection at Indian River. The first involved the DP&L generation re-dispatching to accommodate the new injection, and the second involved reducing the DP&L imports and forcing other PJM generation outside of DP&L to re-dispatch to maintain the system power balance. PTDF contours of each generation re-dispatch scenario (shown in Figure 10 and Figure 11) show the lines most impacted by the shift in power flow from the new injection. Lines that carry more than 25% of the injected power are highlighted in yellow to red. Lines carrying between 10% and 25% are colored in light to dark green. Any transmission elements carrying less than 10% of the injected power are not highlighted. The PTDF contour does not indicate whether the additional flow is increasing or decreasing the total flow on each element.

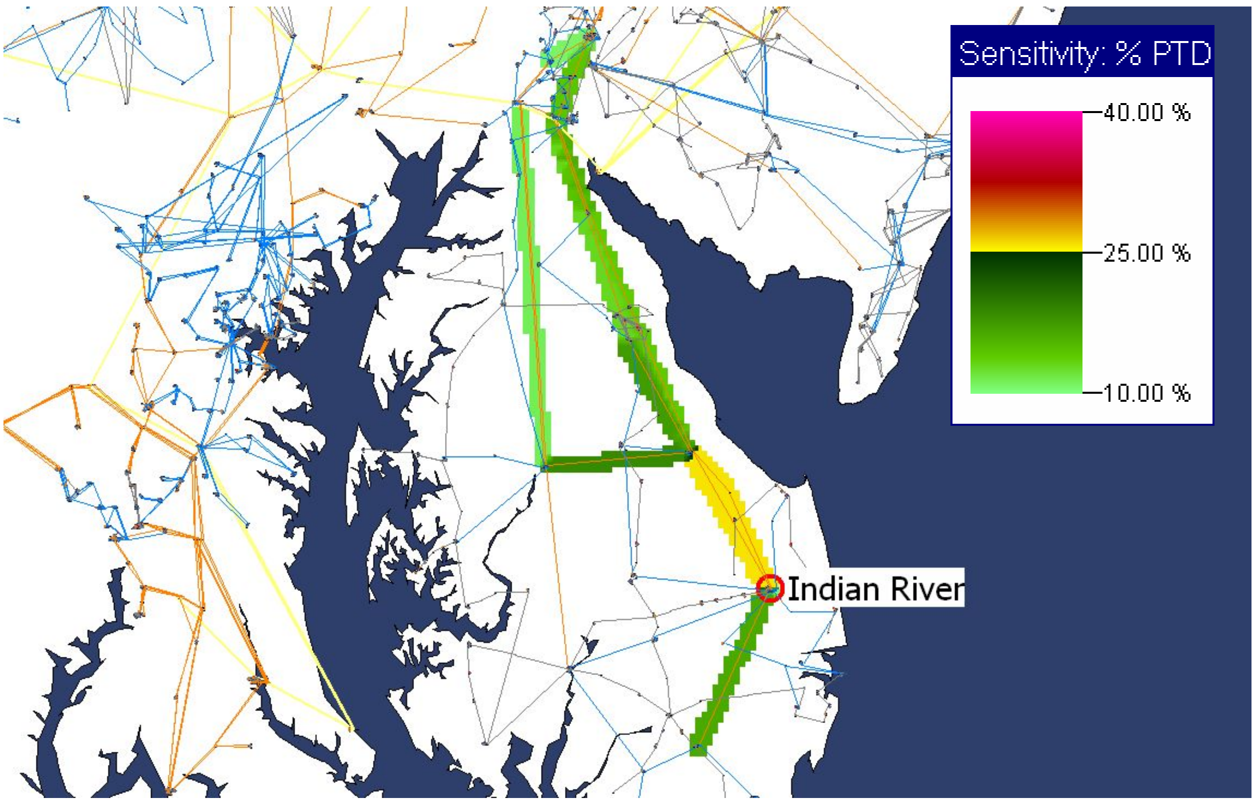

Figure 10 - Indian River Substation PTDF Contour, with Re-dispatch of DP&L Generation

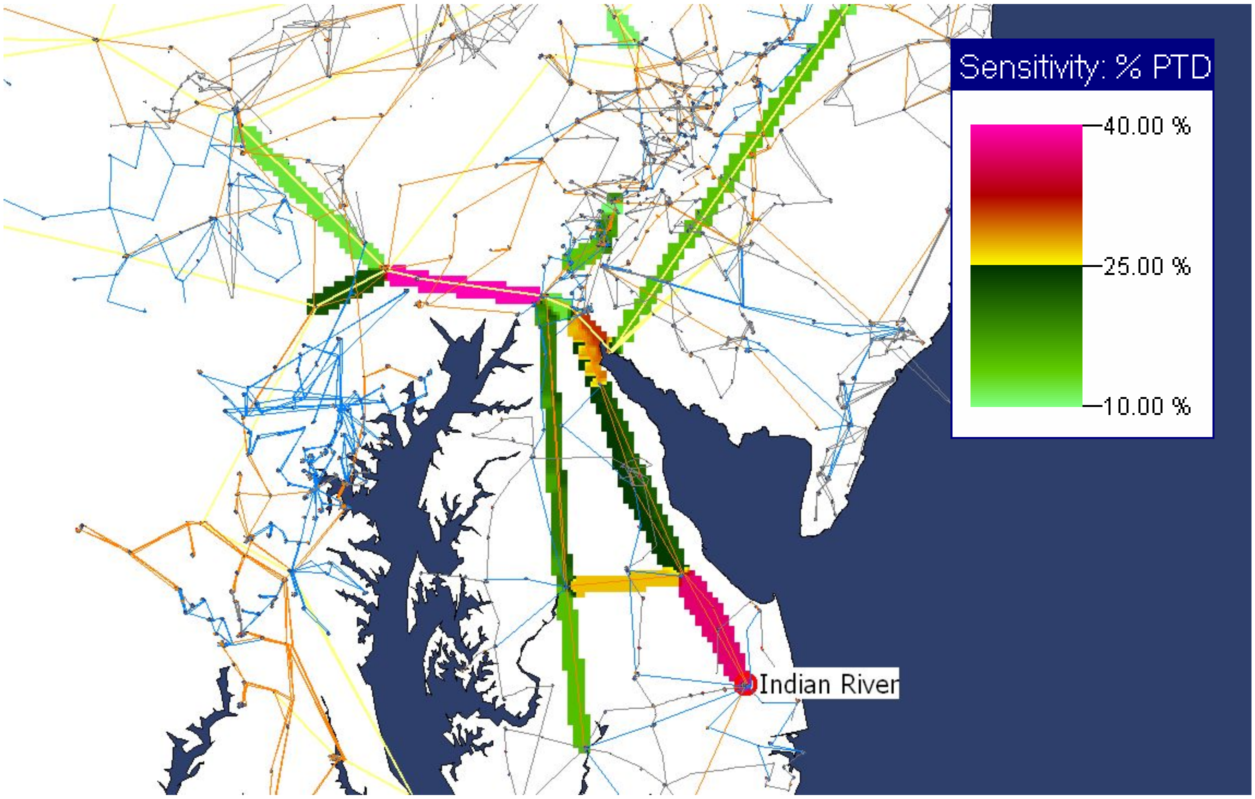

Figure 11 - Indian River Substation PTDF Contour, with Re-dispatch of PJM Generation

Contingency Analysis

Prior to running the contingency analysis, the 600 MW IGCC injection was dispatched at the Indian River 230kV bus, once with the DP&L generation as the sink for the new generation and once with the DP&L imports reducing to offset the new generation. The monitored elements in DP&L were assessed for pre-contingent violations, with no thermal or voltage violations on the DP&L monitored elements observed.

The contingency analysis was then run twice for the 600 MW IGCC connection at Indian River, once each for each sink scenario defined. The results of both contingency runs have been compiled in Table 6 and Table 7 to compare with the original base case contingency violations.

Table 6 - Contingency Thermal Violations for 600 MW IGCC Injection at Indian River

Indian River Injection of 600 MW IGCC (Alternative 2)			Percent Overload		
Overloaded Element	**Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
GLASGOW (8818) -> CECIL138 (9388) CKT 1 (138kV)	79	CECIL (9385) to COLOR_PE (9386) CKT 1 (230kV)	116.11	116.09	116.09
		CECIL3 (9390) to CECIL (9385) CKT 1 (345.5/230kV)	116.11	116.09	116.09
		CONOWG01 (4066) to COLOR_PE (9386) CKT 1 (230kV)			104.66

INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 1 (230/138kV)	478	INDRV2&3 (9176) to INDRIV4 (9171) CKT 2 (138/230kV)	111.64	133.45	129.96
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 2 (230/138kV)	531	INDRV2&3 (9176) to INDRIV4 (9171) CKT 1 (138/230kV)	100.50	120.13	116.98
INDRV2&3 (9176) -> OMAR (9182) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	108.52	110.38	109.93
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	117.74	119.48	119.05
LORETTO (9262) -> LORET_69 (9277) CKT 1 (138/69kV)	66	LORET_69 (9277) to LORETTO (9262) CKT 2 (69/138kV)	114.37	107.22	113.52
LORETTO (9262) -> LORET_69 (9277) CKT 2 (138/69kV)	64	LORET_69 (9277) to LORETTO (9262) CKT 1 (69/138kV)	112.89	105.85	112.03
OAKHL_69 (9330) -> WATTSVIL (9333) CKT 1 (69kV)	91	PINEY_69 (9285) to PINEY138 (9264) CKT 1 (69/138kV)	100.53		101.97
OMAR (9182) -> BETHANY (9173) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	101.40	103.24	102.80
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	109.49	111.20	110.78
WORCR_69 (9210) -> BERLINTP (9186) CKT 1 (69kV)	95	OCNBAY (9203) to OCEANBAY (9177) CKT 1 (69/138kV)	103.17	103.11	103.13

Table 7 - Contingency Voltage Violations for 600 MW IGCC Injection at Indian River

Indian River Injection of 600 MW IGCC (Alternative 2)			Voltage Violations, per unit		
Voltage Violating Bus	**Violated Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
CECIL138 (9388) (138kV)	1.1000	GLASGOW (8818) to CECIL138 (9388) CKT 1 (138kV)			1.1245
FIVE PTS (9193) (69kV)	0.9000	IR4 (9219) to INDRIV4 (9171) CKT 1 (26/230kV)	0.8999		
		BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8937	0.8957	0.8957
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	0.8982	0.8997	0.8998
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8863	0.8883	0.8883
LEWES TP (9197) (69kV)	0.9000	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8997		
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8924	0.8944	0.8943
MIDWAY (9200) (69kV)	0.9000	INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8990		

The first result to notice from the 600 MW IGCC injection contingency analysis is that no new contingent thermal violations occurred on branches that were not already contingent violations in the base case prior to the newly modeled injection. In addition, most of the voltage violations evident in the original base case contingency analysis remain with the addition of the new generation, although they have slightly improved over the base case contingency values.

Indian River Injection to DP&L Generation

Examining the specific contingency results assuming the DP&L generation is sinking the new power at Indian River, it can be seen that the same elements that are overloaded in the base case contingency analysis are again overloaded under this scenario. Of the nine contingent thermal overloaded elements, five elements overload percentages decreased, while the other four elements overload percentages increased. Of the four elements whose overloads increased, the most significant were the increases on the Indian River 230kV to 138kV transformers. These two transformers contingency overload values are 133.45% on transformer 2 and 120.13% on transformer 1. Each of these overload percentages are directly related to the contingency outage of the other transformer. The remaining two transmission elements that increase in contingent overload are the 138kV circuits from Indian River to Omar and Omar to Bethany. The increase of contingent overloads on these elements is due to their close electrical proximity to the added generation at the Indian River 230kV bus. These elements experience contingency overloads without the new generation, however remedial actions involving the new generation may be adopted by DP&L as part of their operating procedures since the new generation increases the contingent overload percentages. The locations of all contingency overloaded elements for this scenario are shown in Figure 12, with elements experiencing overloads for one contingency highlighted dark blue, and elements experiencing overloads for two contingencies highlighted slate blue. All contingent overloads occurred on elements electrically close to the Indian River injection point, with the exception of the Glasgow to Cecil 138kV circuit, located much farther to the North.

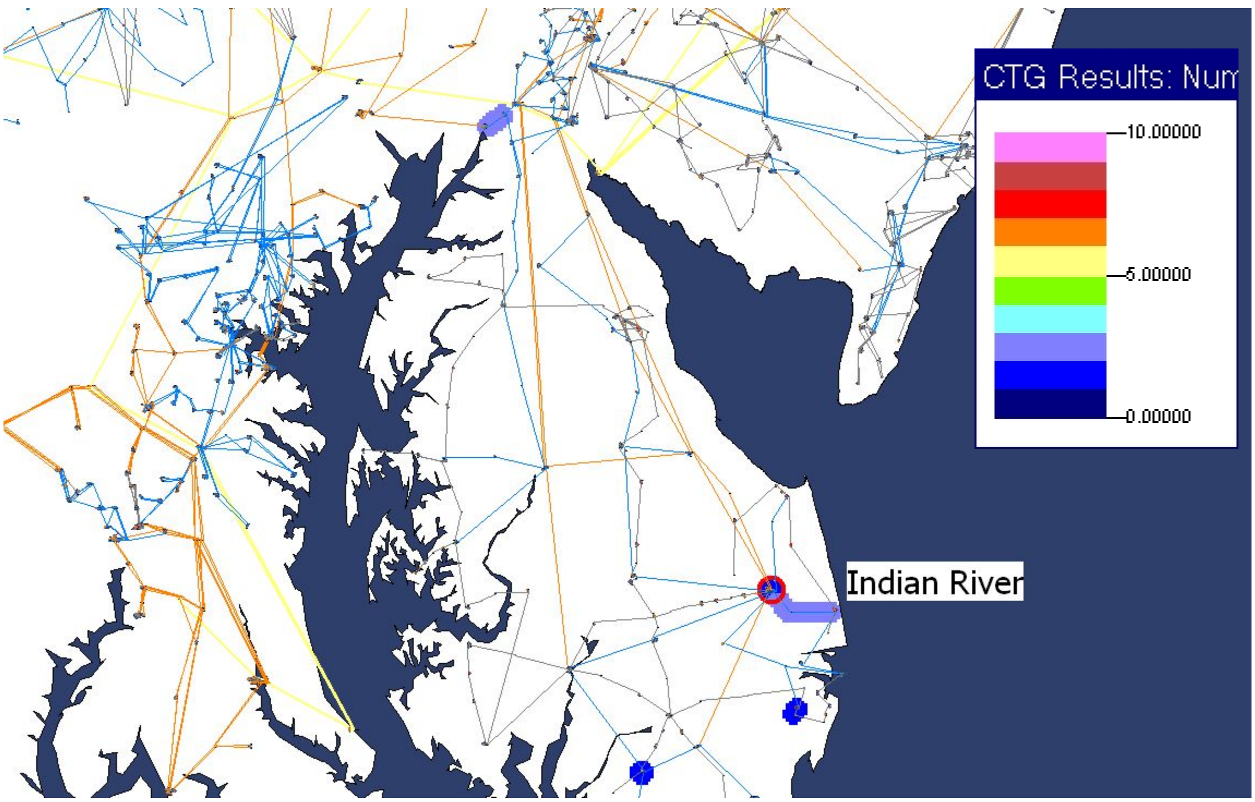

Figure 12 - Highlighting Transmission Elements Experiencing Contingency Overloads – Indian River to DP&L

The contingent voltage violations that occur with the injection of 600 MW at Indian River, offset by DP&L generation, are at the same buses that experience voltage violations under the base case contingency analysis. Comparing values in Table 7 indicates that the voltage violations are not quite as severe with the Indian River generation in place, but that the voltage violations are not improved significantly. This indicates that the three 69kV buses that experience contingency overloads are not highly impacted by the additional voltage support the new Indian River generation provides.

Indian River Injection to DP&L Import Offset

The results of the Indian River IGCC injection offset by reducing DP&L imports are very similar to the DP&L generation offset scenario. The same elements displaying contingency violations during the DP&L generation offset scenario appear in the import offset scenario, with slightly lower overload percentages. The locations of the contingency overloaded elements are shown in Figure 7, with elements experiencing overloads for one contingency highlighted dark blue, for two contingencies highlighted slate blue, and for three contingencies highlighted light blue. All contingent overloads occurred on elements electrically close to the Bethany injection point, with the exception of the Glasgow to Cecil 138kV circuit, located much farther to the North.

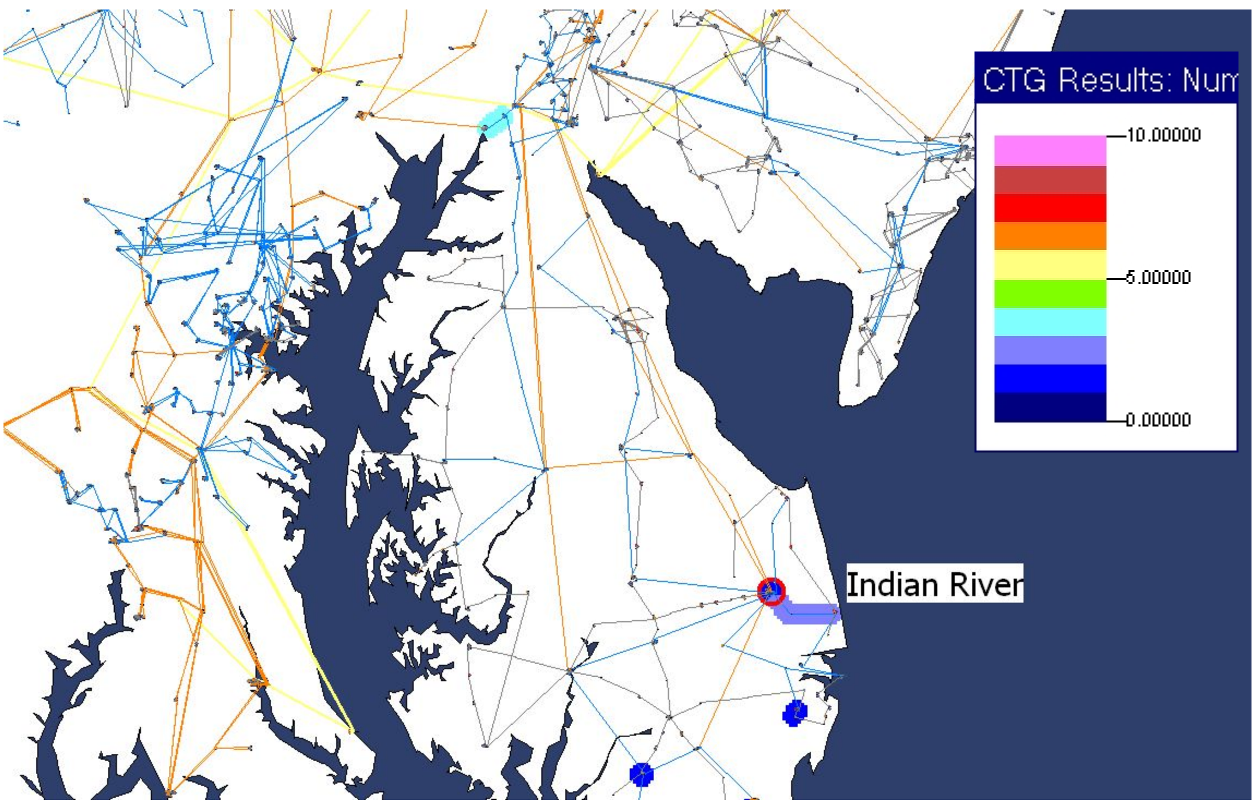

Figure 13 - Highlighting Transmission Elements Experiencing Contingency Overloads – Indian River to PJM

The only new contingent voltage violation that occurs with the injection of 600 MW at Indian River, offset by PJM generation, is a high voltage violation at the Cecil 138kV bus during the contingency outage of the Glasgow to Cecil 138kV branch. This high voltage situation may or may not be of serious consequence, and may be handled with remedial actions by DP&L should the contingency occur. The remaining voltage violations listed in Table 7 for the PJM offset scenario are nearly identical to the violations observed for the DP&L offset. This reinforces that these 69kV contingent bus voltage problems are not highly responsive to the additional VAR support the new Indian River generation provides.

Summary

The general conclusions from both generation offset scenarios for the 600 MW IGCC at the Indian River 230kV substation are that the Indian River injection does not introduce any new contingency violations than already identified in the base case contingency results, but does however make some of those contingent violations more severe. DP&L would need to assess these adversely affected violation scenarios more thoroughly, and determine courses of action related to each potential contingent overload.

The new Indian River injection does not necessarily indicate any significant improvement to contingent voltage violations on the 69kV system compared to the base case results. However, the new Indian River combined cycle plant would still be a great benefit to voltage reliability in the region. As discussed in the base case preparation, the analysis here considered the Indian River units 1 and 2 retired. It was also discussed that with those retirements, the steady state voltage in the region on the 230kV system was much more susceptible to voltage drop due to reduced VAR sources in the region. The new IGCC at Indian River would greatly help by providing an additional VAR source. In the case of the discussed scenario of the Indian River 4 unit outage, it was previously noted that the largest 230kV voltage drop was 6.75 volts with Indian River 1 and 2 retired. With the inclusion of the Indian River IGCC, the same outage of Indian River 4 results in all 230kV voltages being maintained at nearly the same level as the pre-contingent voltages. This is due to the fact that the new IGCC was modeled as injected at the same point as the existing Indian River 4 unit. These two units should compliment each other well for voltage regulation if one or the other experiences either a planned or unplanned outage.

Alternative 3: 177 MW CCGT Power Plant at Red Lion Substation

The interconnection of the proposed 177 MW CCGT power plant is detailed to occur at the 230kV Red Lion substation. This substation is located in the Northern region of DP&L, whereas the other three generation alternative locations are located in the Southern DP&L electrical territory.

Load Flow Model Representation

The interconnection was modeled with a new generator at the existing Red Lion 230kV substation. The generation was set to 177 MW directly into the Red Lion 230kV bus. The voltage support of the new generation was given a large range of operation under the assumption that ample VAR support would be available. The voltage regulation of the new generator was set to 1.04 per unit voltage of the Red Lion 230kV terminal bus. The voltage regulation value was determined by examining regulation voltage settings of other generators and voltage controlling devices in the vicinity of the Red Lion substation. Figures 1 and 2 illustrate the proposed electrical connection.

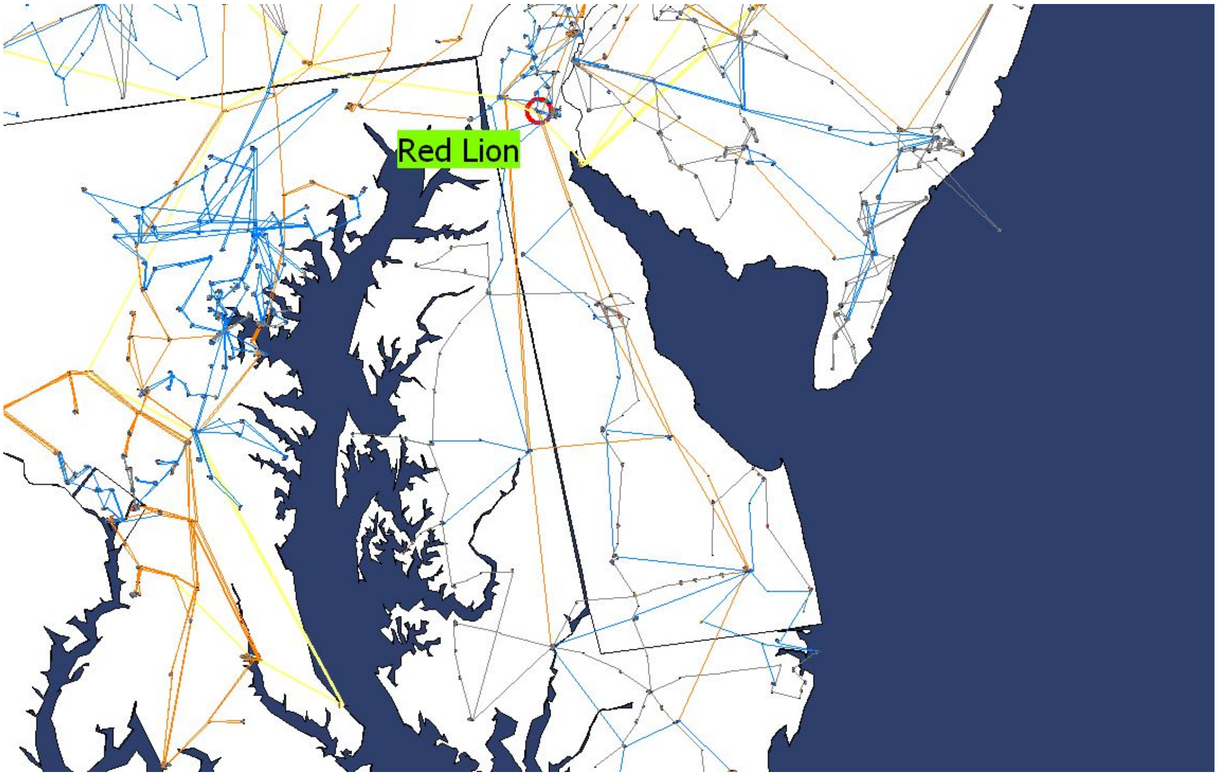

Figure 14 - Red Lion Substation Location

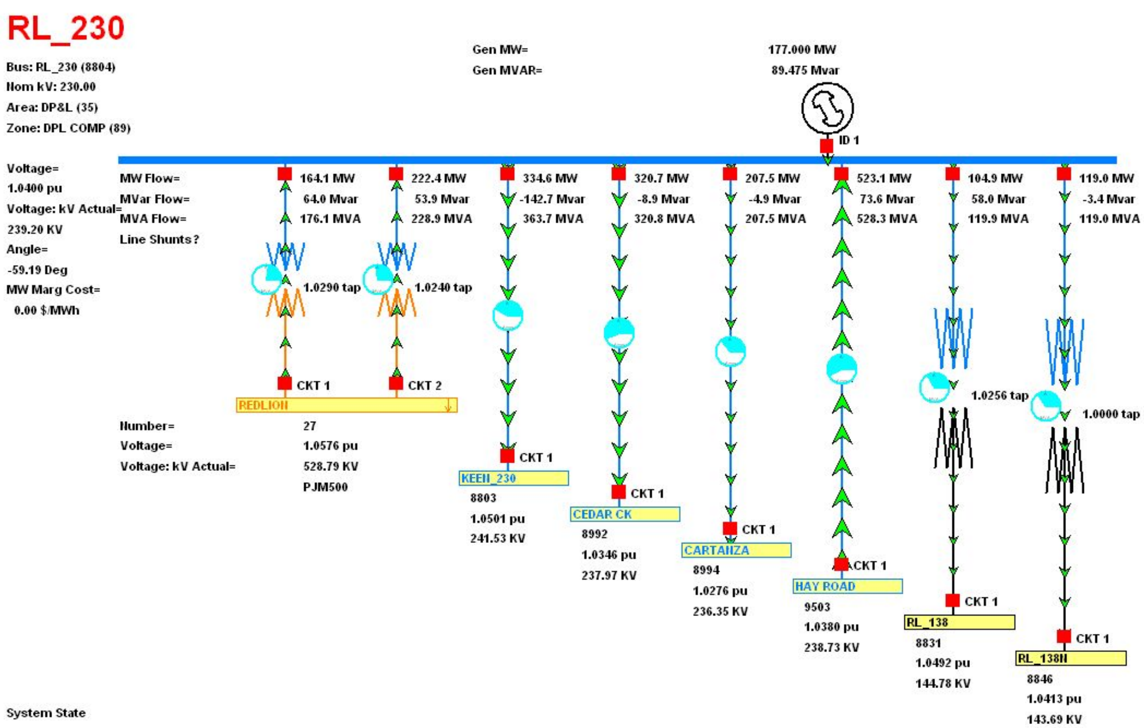

Figure 15 - Red Lion 230kV Bus, Showing New Generation and Load Flows

Two different scenarios of generation offset were considered for the new injection at Red Lion. The first involved the DP&L generation re-dispatching to accommodate the new injection, and the second involved reducing the DP&L imports and forcing other PJM generation outside of DP&L to re-dispatch to maintain the system power balance. PTDF contours of each generation re-dispatch scenario (shown in Figure 16 and Figure 17) show the lines most impacted by the shift in power flow from the new injection. Lines that carry more than 25% of the injected power are highlighted in yellow to red. Lines carrying between 10% and 25% are colored in light to dark green. Any transmission elements carrying less than 10% of the injected power are not highlighted. The PTDF contour does not indicate whether the additional flow is increasing or decreasing the total flow on each element.

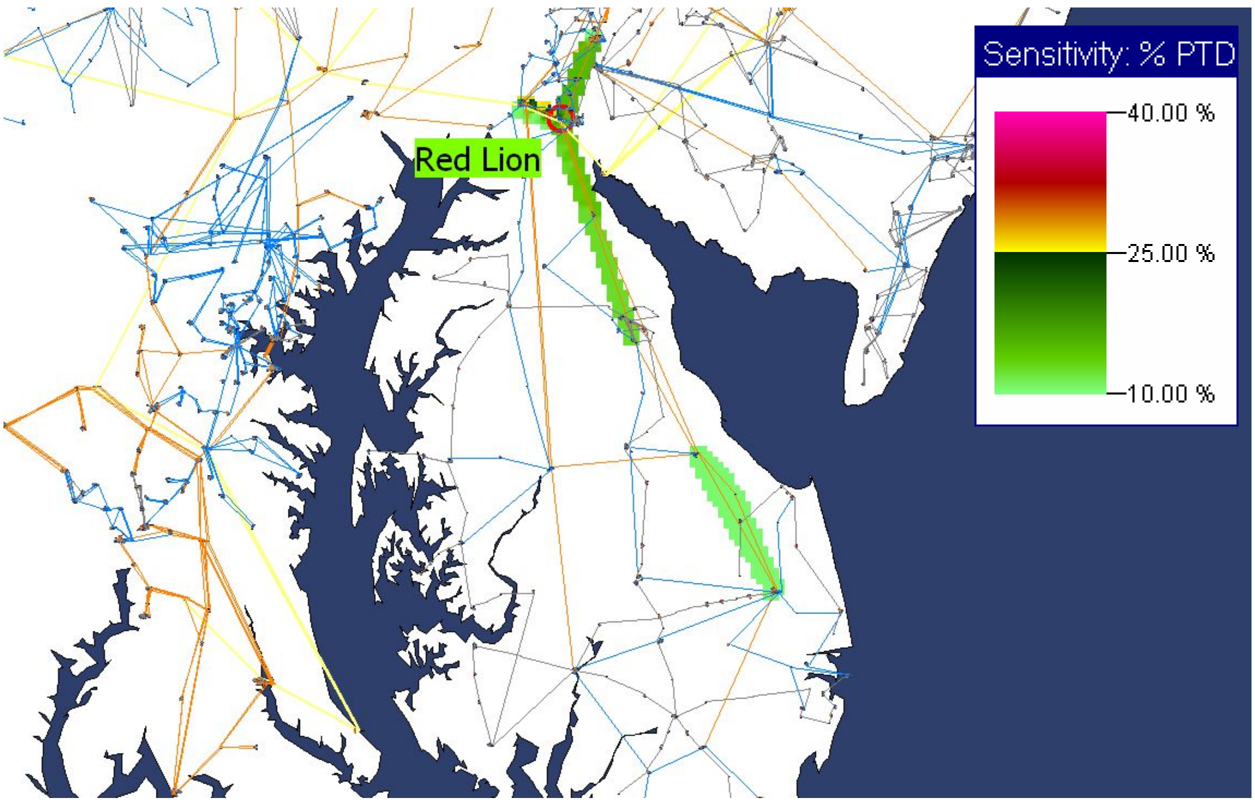

Figure 16 – Red Lion Substation PTDF Contour, with Re-dispatch of DP&L Generation

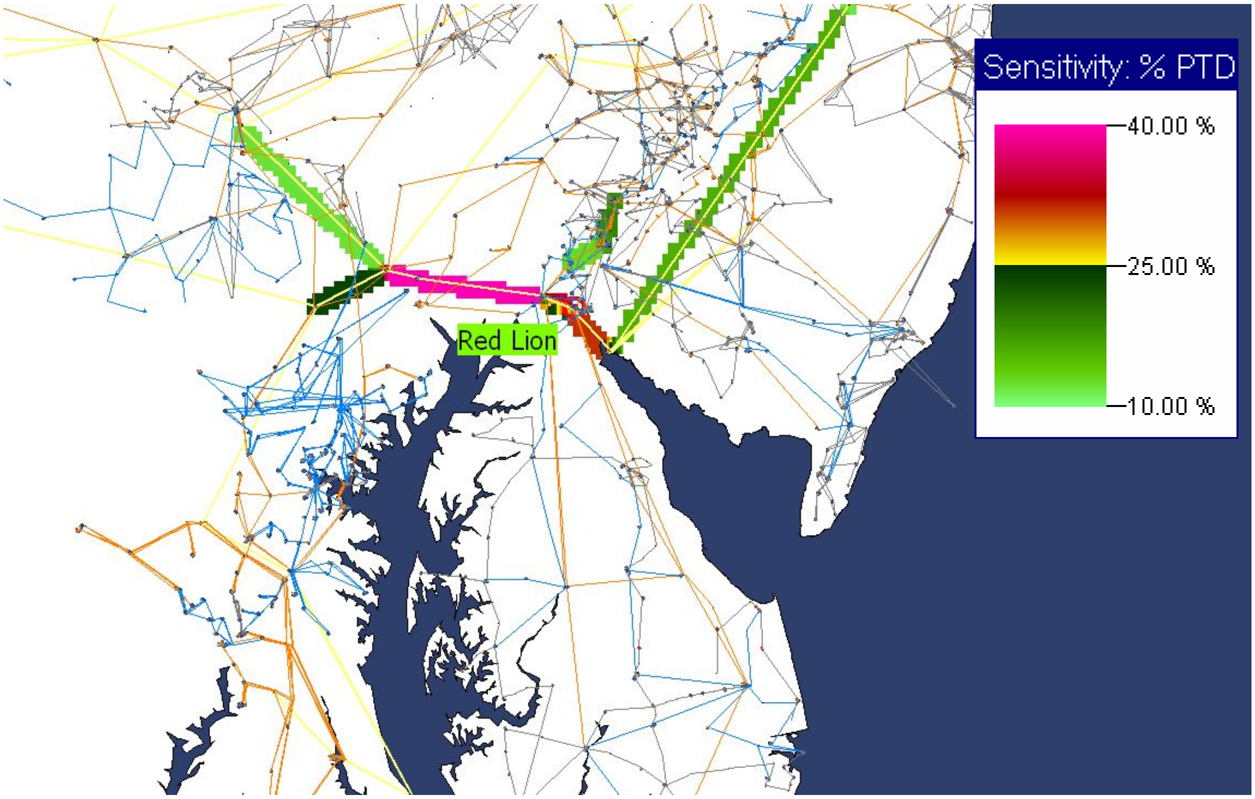

Figure 17 - Red Lion Substation PTDF Contour, with Re-dispatch of PJM Generation

Contingency Analysis

Prior to running the contingency analysis, the 177 MW CCGT injection was dispatched at the Red Lion 230kV bus, once with the DP&L generation as the sink for the new generation and once with the DP&L imports reducing to offset the new generation. The monitored elements in DP&L were assessed for pre-contingent violations, with no thermal or voltage violations on the DP&L monitored elements observed.

The contingency analysis was then run twice for the 177 MW CCGT connection at Red Lion, once for each sink scenario defined. The results of both contingency runs have been compiled in Table 8 and Table 9 to compare with the original base case contingency violations.

Table 8 - Contingency Thermal Violations for 177 MW IGCC Injection at Red Lion

Red Lion Injection 177 MW CCGT (Alternative 3)			Percent Overload		
Overloaded Element	**Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
CHURCH (9072) -> CHURC_69 (9088) CKT 1 (138/69kV)	75	CHURC_69 (9088) to CHURCH (9072) CKT 2 (69/138kV)		102.28	
GLASGOW (8818) -> CECIL138 (9388) CKT 1 (138kV)	79	CECIL (9385) to COLOR_PE (9386) CKT 1 (230kV)	116.11	116.08	116.08
		CECIL3 (9390) to CECIL (9385) CKT 1 (345.5/230kV)	116.11	116.08	116.08

INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 1 (230/138kV)	478	INDRV2&3 (9176) to INDRIV4 (9171) CKT 2 (138/230kV)	111.64	112.64	111.59
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 2 (230/138kV)	531	INDRV2&3 (9176) to INDRIV4 (9171) CKT 1 (138/230kV)	100.50	101.40	100.45
INDRV2&3 (9176) -> OMAR (9182) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	108.52	108.64	108.50
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	117.74	117.85	117.72
LORETTO (9262) -> LORET_69 (9277) CKT 1 (138/69kV)	66	LORET_69 (9277) to LORETTO (9262) CKT 2 (69/138kV)	114.37	112.51	114.30
LORETTO (9262) -> LORET_69 (9277) CKT 2 (138/69kV)	64	LORET_69 (9277) to LORETTO (9262) CKT 1 (69/138kV)	112.89	111.07	112.82
OAKHL_69 (9330) -> WATTSVIL (9333) CKT 1 (69kV)	91	PINEY_69 (9285) to PINEY138 (9264) CKT 1 (69/138kV)	100.53		100.52
OMAR (9182) -> BETHANY (9173) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	101.40	101.52	101.39
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	109.49	109.60	109.48
WORCR_69 (9210) -> BERLINTP (9186) CKT 1 (69kV)	95	OCNBAY (9203) to OCEANBAY (9177) CKT 1 (69/138kV)	103.17	103.16	103.16

Table 9 - Contingency Voltage Violations for 177 MW IGCC Injection at Red Lion

Red Lion Injection 177 MW CCGT (Alternative 3)			**Voltage Violations, per unit**		
Voltage Violating Bus	**Violated Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
FIVE PTS (9193) (69kV)	0.9000	IR4 (9219) to INDRIV4 (9171) CKT 1 (26/230kV)	0.8999		
		BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8937	0.8938	0.8940
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	0.8982	0.8983	0.8984
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8863	0.8865	0.8866
LEWES TP (9197) (69kV)	0.9000	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8997	0.8999	0.9000
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8924	0.8926	0.8927
MIDWAY (9200) (69kV)	0.9000	INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8990	0.8992	0.8993

The primary result to notice from the 177 MW CCGT injection contingency analyses is that no new contingent thermal violations occurred on branches that were not already contingent violations in the base case prior to the newly modeled injection. In addition, most of the voltage violations evident in the original base case contingency analysis remain with the addition of the new generation, although they have slightly improved over the base case contingency values.

Red Lion Injection to DP&L Generation

Examining the specific contingency results assuming the DP&L generation is sinking the new power at Red Lion, it can be seen that the same elements that are overloaded in the base case contingency analysis are again overloaded under this scenario. There is, however, one additional element that is contingency overloaded only in this scenario, that being 102.28% on the Church 69kV to 138kV circuit 1 transformer, when a contingency outage occurs on the parallel circuit 2 transformer. The remaining contingency thermal violations are generally the same as the base case contingency violations, with the largest difference being a 1.86% decrease in the overload of the Loretto 69kV to 138kV circuit 1 transformer when the parallel circuit 2 transformer contingency outage occurs. The locations of the contingency overloaded elements are shown in Figure 18, with elements experiencing overloads for one contingency highlighted dark blue, and elements experiencing overloads for two contingencies highlighted slate blue. Most of the contingency violations occurred in the Southern region of DP&L, and were little affected by the 177 MW injection in the North at Red Lion. The two contingent violations closest to Red Lion are the Glasgow to Cecil 138kV branch and the Church 69kV to 138kV transformer.

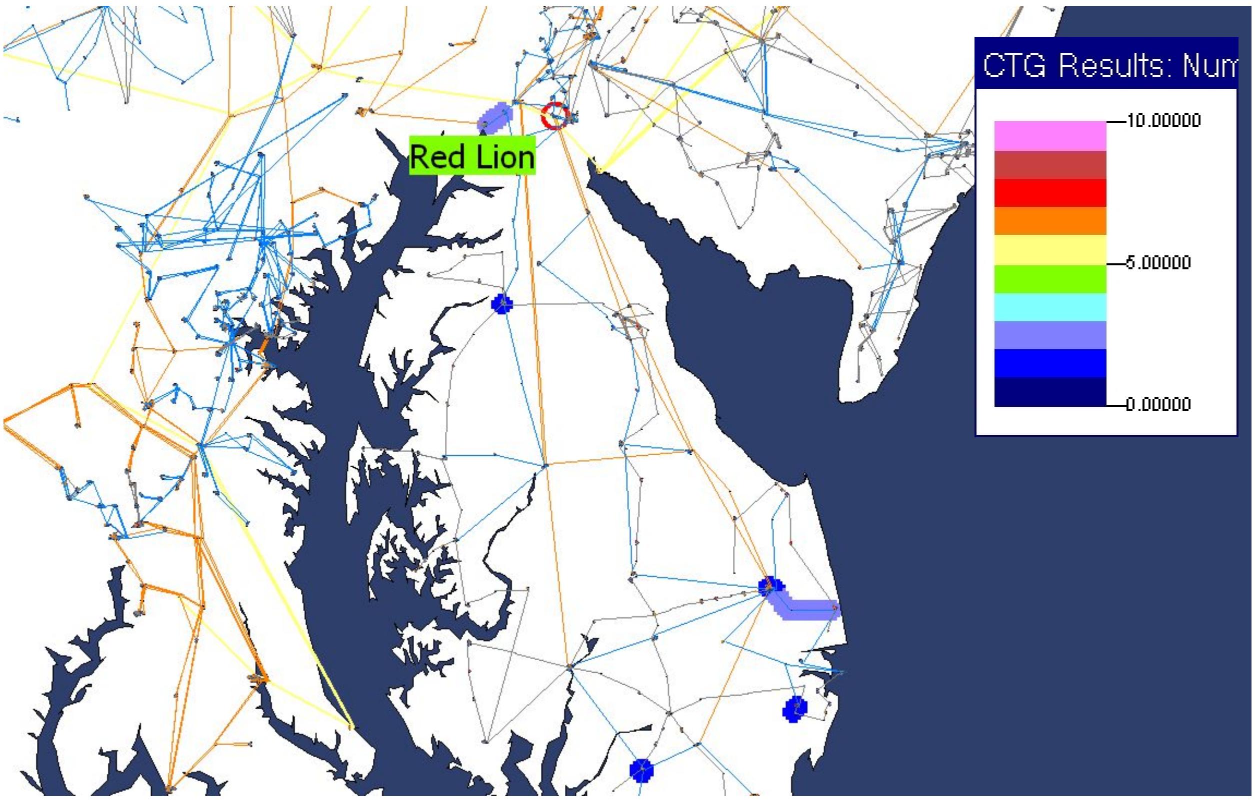

Figure 18 - Highlighting Transmission Elements Experiencing Contingency Overloads – Red Lion to DP&L

The contingent voltage violations that occur with the injection of 177 MW at Red Lion, offset by DP&L generation, are at the same buses that experience voltage violations under the base case contingency analysis. Comparing values in Table 9 indicates that the voltage violations improved slightly with the Red Lion generation in place, but that the voltage violations are not improved significantly. The improvement is likely due mainly to the remaining Indian River units decreasing in output as part of the generation offset for the new 177 MW of generation at Red Lion. Given the electrical distance of the Red Lion substation from the three 69kV buses that experience contingency overloads, it is highly unlikely that the voltage support provided from the new Red Lion generation has any affect on the voltages at these three buses.

Red Lion Injection to DP&L Import Offset

The results of the Red Lion CCGT injection offset by reducing DP&L imports are very similar to the DP&L generation offset scenario, although the Church 69kV to 138kV transformer contingent overload does not appear when reducing DP&L imports as it does when reducing DP&L generation as the injection sink. All other contingent violations are on the same elements as the base case contingent thermal violations. The change in the thermal violation percentages are very small, indicating that installing the generation at Red Lion and offsetting imports into DP&L affects the flow on elements in Southern DP&L very little. This is evident if you refer back to the PTDF contour in Figure 17, which shows a bulk of the new generation at Red Lion flowing away to the North when the DP&L imports are reduced by the new generator injection amount. Most of the contingency violations occurred in the Southern region of DP&L, and were little affected by the 177MW injection in the North at Red Lion. Only the contingent violations on the Glasgow to Cecil 138kV branch are electrically nearby, but they are also little affected by the Red Lion injection.

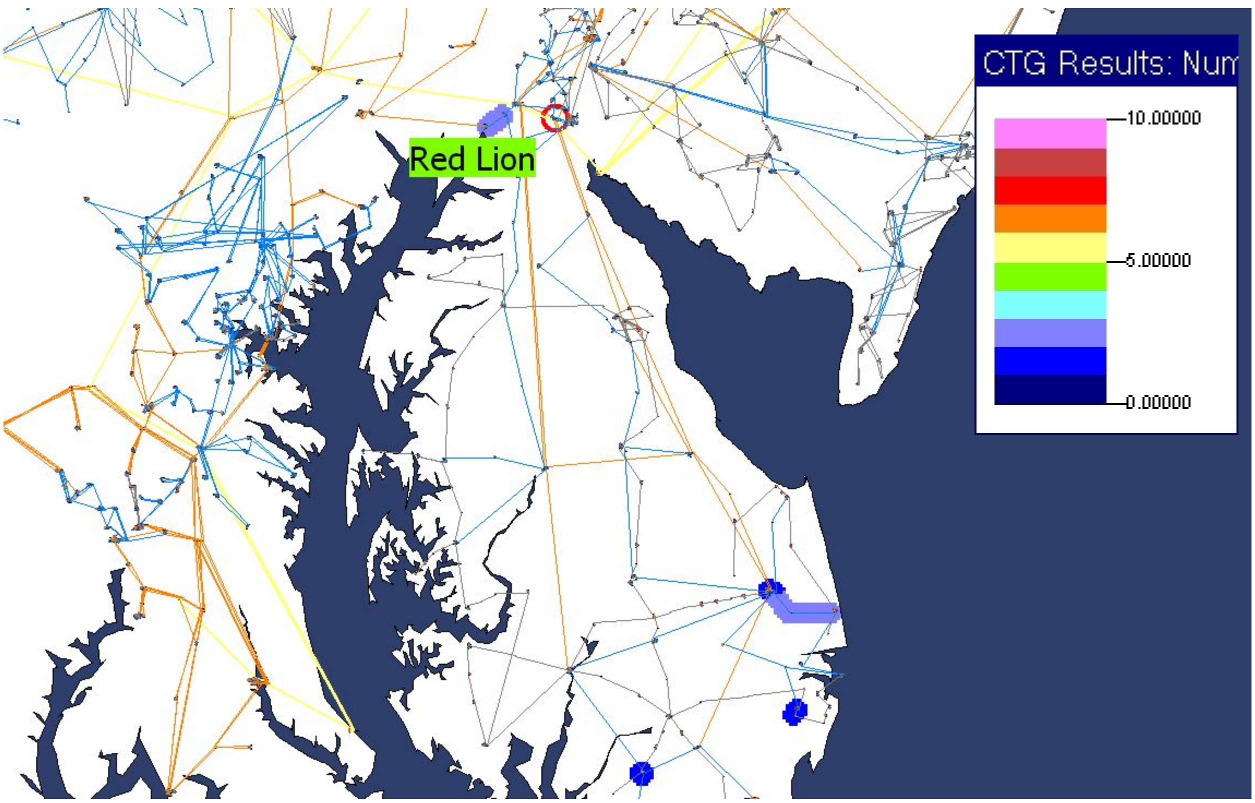

Figure 19 - Highlighting Transmission Elements Experiencing Contingency Overloads – Red Lion to PJM

The contingent voltage violations that occur with the injection of 177 MW at Red Lion, offset by DP&L import reduction, are at the same buses that experience voltage violations under the base case contingency analysis. Comparing values in Table 9 indicates that the voltage violations improved slightly with the Red Lion generation in place, but that the voltage violations are not improved significantly. Given the electrical distance of the Red Lion substation from the three

69kV buses that experience contingency overloads, it is highly unlikely that the voltage support provided from the new Red Lion generation has any affect on the voltages at these three buses. The voltage changes are more likely due to slight shifts in branch flows from the reduced imports and Red Lion injection.

Summary

The general conclusions from both generation offset scenarios for the 177 MW CCGT at the Red Lion 230kV substation are that the Red Lion injection does not introduce any significant new contingency violations than already identified in the base case contingency results. Furthermore, the new injection impact on the base case contingency violations is very small. The two factors for why the Red Lion injection has little impact on the pre-existing contingency violations are the location of the Red Lion substation relative to the base case contingency violations and that the amount of the injection is only 177 MW. A larger injection at Red Lion still may not have affected the pre-existing contingent violations, but may have introduced more new contingent violations in Northern DP&L. The voltage violations identified in the base case are on the 69kV system, and as VAR support is typically a localized affect, the voltage support provided by the new Red Lion injection at the 230kV level is not far-reaching and does not help the problems observed on the lower voltage system in the South.

Alternative 4: 600 MW Wind Farm at Bethany Substation and 177 MW CCGT at Nelson Substation

Interconnection of the proposed 600 MW offshore wind farm was detailed to occur through four 138kV submarine cable circuits at either the 138kV Rehoboth bus or the 138kV Bethany bus in DP&L. Discussions with Commission staff led to focusing the analysis at the Bethany 138kV interconnection point for this analysis. The additional 177 MW CCGT was detailed to occur at the Nelson Substation, to the West of the Bethany substation. This is the only alternative of the four studied which combines generation technologies and multiple injection locations.

Load Flow Model Representation

The interconnection was modeled with a new generator at the existing Bethany 138kV substation and a second new generator at the Nelson 138kV substation. The first generation was set to 600 MW directly into the Bethany 138kV bus. The second generation was set to 177 MW directly into the Nelson 138kV bus. The voltage support of the new generation was given a large range of operation under the assumption that ample VAR support would be available. The voltage regulation of both new generators was set to 1.04 per unit voltage of the Bethany 138kV and Nelson 138kV terminal buses. The voltage regulation value was determined by examining regulation voltage settings of other generators and voltage controlling devices in the vicinity of the Bethany and Nelson substations. Figure 20, Figure 21, and Figure 22 illustrate the proposed electrical connections.

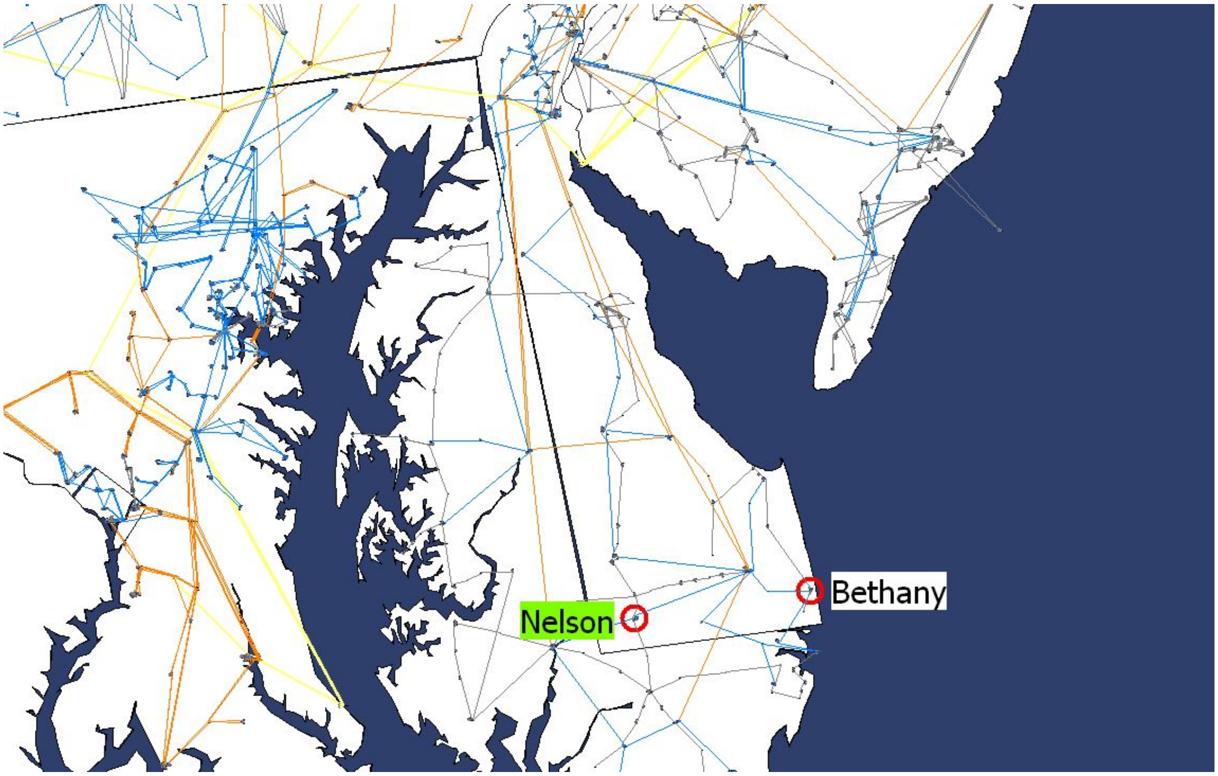

Figure 20 - Bethany and Nelson Substation Locations

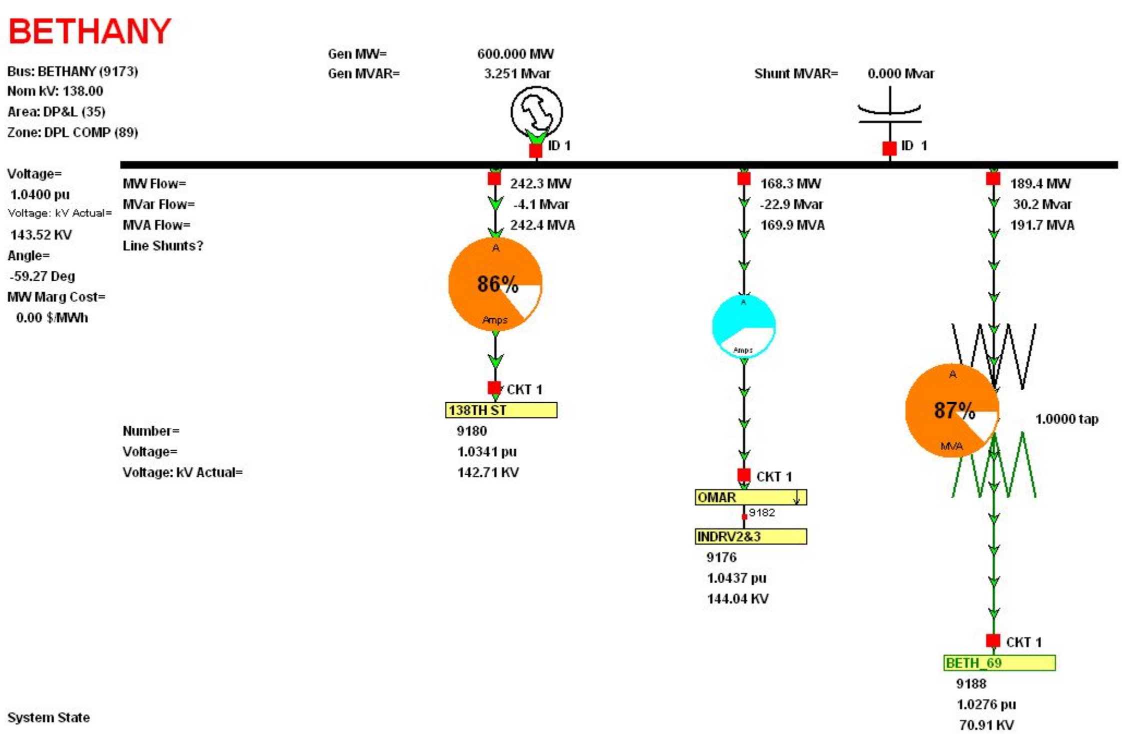

Figure 21 - Bethany 138kV Bus, Showing New Generation and Load Flows

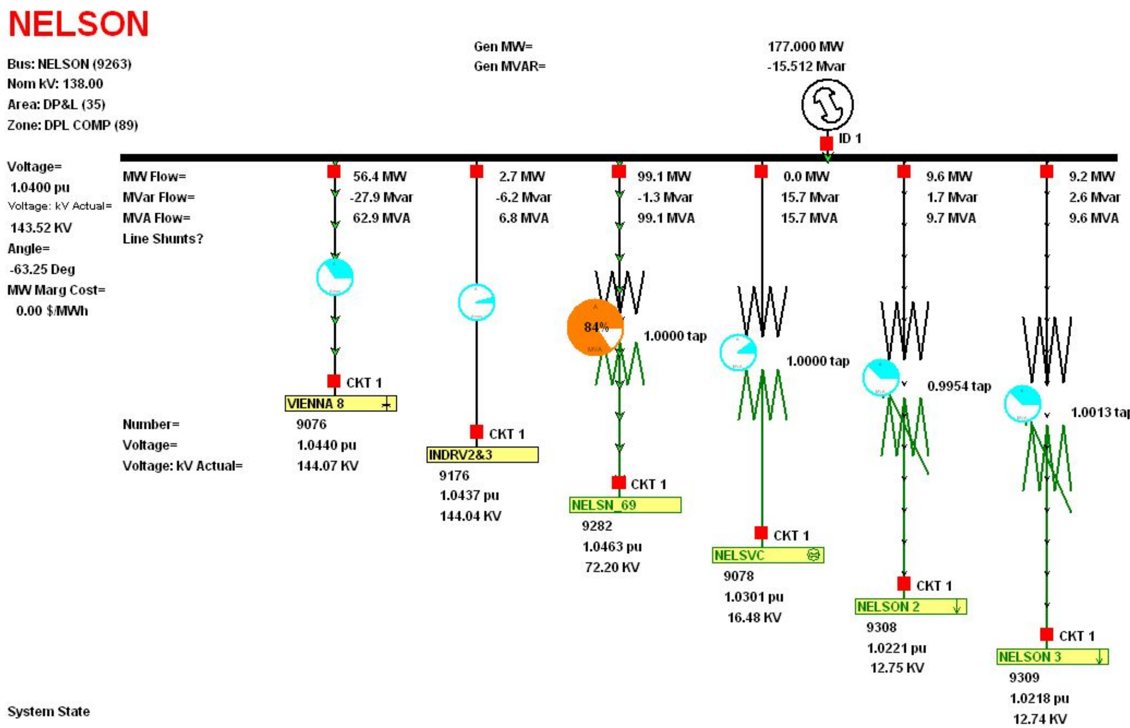

Figure 22 - Nelson 138kV Bus, Showing New Generation and Load Flows

Two different scenarios of generation offset were considered for the new injection at Bethany and Nelson. The first involved the DP&L generation re-dispatching to accommodate the new injection, and the second involved reducing the DP&L imports and forcing other PJM generation outside of DP&L to re-dispatch to maintain the system power balance. PTDF contours of each generation re-dispatch scenario (shown in Figure 23 and Figure 24) show the lines most impacted by the shift in power flow from the new injection. Lines that carry more than 25% of the injected power are highlighted in yellow to red. Lines carrying between 10% and 25% are colored in light to dark green. Any transmission elements carrying less than 10% of the injected power are not highlighted. The PTDF contour does not indicate whether the additional flow is increasing or decreasing the total flow on each element.

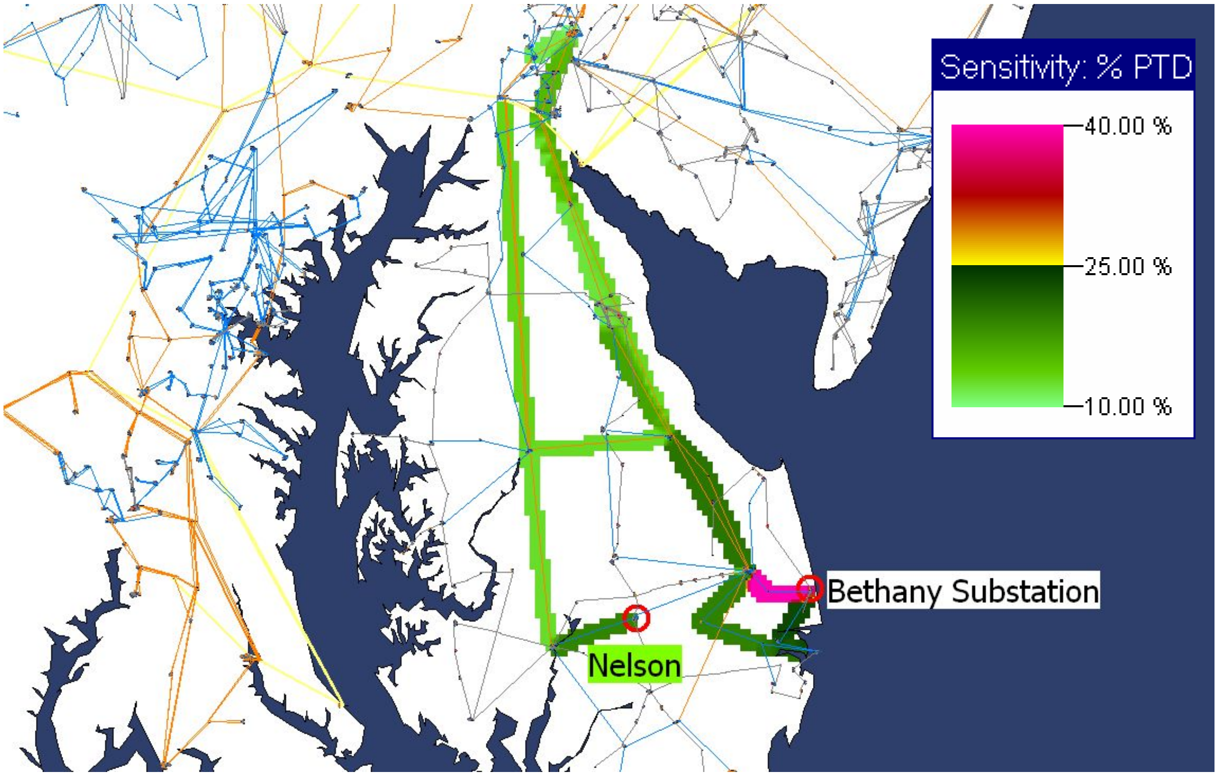

Figure 23 – Bethany and Nelson PTDF Contour, with Re-dispatch of DP&L Generation

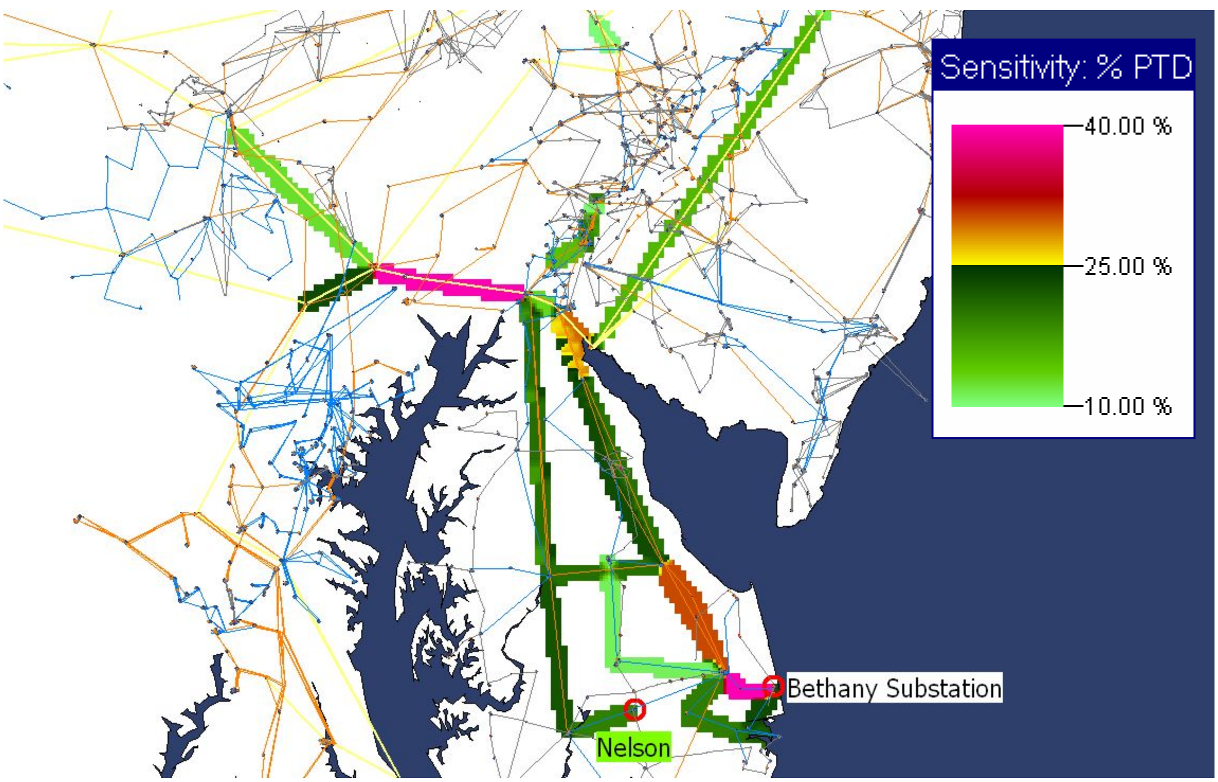

Figure 24 - Bethany and Nelson PTDF Contour, with Re-dispatch of PJM Generation

Contingency Analysis

Prior to running the contingency analysis, the 600 MW wind farm injection was dispatched at the Bethany 138kV bus and the 177 CCGT was dispatched at the Nelson 138kV bus. The combined generation was dispatched once with the DP&L generation as the sink for the new generation and once with the DP&L imports reducing to offset the new generation. The monitored elements in DP&L were assessed for pre-contingent violations, with no thermal or voltage violations on the DP&L monitored elements observed.

The contingency analysis was then run twice for the 777 MW total injection, once each for each sink scenario defined. The results of both contingency runs have been compiled in Table 10 and

Bethany Injection 600 MW Windfarm and Nelson Injection 177 MW CCGT (Alternative 4)			**Percent Overload**		
Overloaded Element	**Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
BETHANY (9173) -> 138TH ST (9180) CKT 1 (138kV)	348	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)		107.55	107.46
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)		104.09	103.99
BETHANY (9173) -> OMAR (9182) CKT 1 (138kV)	336	BETHANY (9173) to 138TH ST (9180) CKT 1 (138kV)		113.87	113.86
		OCEANBAY (9177) to 138TH ST (9180) CKT 1 (138kV)		101.43	101.42
EDGEMR 3 (8859) -> DUP-EM (8857) CKT 1 (69kV)	143	CLAY_230 (8800) to EDGEMR 5 (8801) CKT 1 (230kV)			100.87
GLASGOW (8818) -> CECIL138 (9388) CKT 1 (138kV)	79	LINWOOD (4558) to CLAY_230 (8800) CKT 1 (230kV)			100.26
		CECIL (9385) to COLOR_PE (9386) CKT 1 (230kV)	116.11	116.09	116.08
		CECIL3 (9390) to CECIL (9385) CKT 1 (345.5/230kV)	116.11	116.09	116.08
		CONOWG01 (4066) to COLOR_PE (9386) CKT 1 (230kV)			108.02
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 1 (230/138kV)	478	INDRV2&3 (9176) to INDRIV4 (9171) CKT 2 (138/230kV)	111.64		
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 2 (230/138kV)	531	INDRV2&3 (9176) to INDRIV4 (9171) CKT 1 (138/230kV)	100.50		
INDRV2&3 (9176) -> OMAR (9182) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	108.52		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	117.74		
LORETTO (9262) -> LORET_69 (9277) CKT 1 (138/69kV)	66	LORET_69 (9277) to LORETTO (9262) CKT 2 (69/138kV)	114.37		100.81
LORETTO (9262) -> LORET_69 (9277) CKT 2 (138/69kV)	64	LORET_69 (9277) to LORETTO (9262) CKT 1 (69/138kV)	112.89		
MARIDEL (9199) -> OCEANCTY (9204) CKT 1 (69kV)	116	BISHOP (9174) to WORCESTR (9179) CKT 1 (138kV)		103.82	102.14
		WORCR_69 (9210) to WORCESTR (9179) CKT 1 (69/138kV)		103.83	102.15
NSEAF_69 (9021) -> TAYLOR (9024) CKT 1 (69kV)	64	SHARR_69 (9023) to SHARNGTN (9004) CKT 1 (69/138kV)		103.11	105.78
OAKHL_69 (9330) -> WATTSVIL (9333) CKT 1 (69kV)	91	PINEY_69 (9285) to PINEY138 (9264) CKT 1 (69/138kV)	100.53		
OCNBAY (9203) -> MARIDEL (9199) CKT 1 (69kV)	137	BISHOP (9174) to WORCESTR (9179) CKT 1 (138kV)		112.34	110.85
		WORCR_69 (9210) to WORCESTR (9179) CKT 1 (69/138kV)		112.34	110.85
OMAR (9182) -> BETHANY (9173) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	101.40		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	109.49		

OMAR (9182) -> INDRV2&3 (9176) CKT 1 (138kV)	336	BETHANY (9173) to 138TH ST (9180) CKT 1 (138kV)		109.22	109.18
WORCR_69 (9210) -> BERLINTP (9186) CKT 1 (69kV)	95	OCNBAY (9203) to OCEANBAY (9177) CKT 1 (69/138kV)	103.17	102.95	102.96

Table 11 to compare with the original base case contingency violations.

Table 10 - Contingency Thermal Violations for 777 MW Total Injection at Bethany and Nelson

Bethany Injection 600 MW Windfarm and Nelson Injection 177 MW CCGT (Alternative 4)			Percent Overload		
Overloaded Element	**Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
BETHANY (9173) -> 138TH ST (9180) CKT 1 (138kV)	348	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)		107.55	107.46
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)		104.09	103.99
BETHANY (9173) -> OMAR (9182) CKT 1 (138kV)	336	BETHANY (9173) to 138TH ST (9180) CKT 1 (138kV)		113.87	113.86
		OCEANBAY (9177) to 138TH ST (9180) CKT 1 (138kV)		101.43	101.42
EDGEMR 3 (8859) -> DUP-EM (8857) CKT 1 (69kV)	143	CLAY_230 (8800) to EDGEMR 5 (8801) CKT 1 (230kV)			100.87
GLASGOW (8818) -> CECIL138 (9388) CKT 1 (138kV)	79	LINWOOD (4558) to CLAY_230 (8800) CKT 1 (230kV)			100.26
		CECIL (9385) to COLOR_PE (9386) CKT 1 (230kV)	116.11	116.09	116.08
		CECIL3 (9390) to CECIL (9385) CKT 1 (345.5/230kV)	116.11	116.09	116.08
		CONOWG01 (4066) to COLOR_PE (9386) CKT 1 (230kV)			108.02
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 1 (230/138kV)	478	INDRV2&3 (9176) to INDRIV4 (9171) CKT 2 (138/230kV)	111.64		
INDRIV 4 (9171) -> INDRV2&3 (9176) CKT 2 (230/138kV)	531	INDRV2&3 (9176) to INDRIV4 (9171) CKT 1 (138/230kV)	100.50		
INDRV2&3 (9176) -> OMAR (9182) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	108.52		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	117.74		
LORETTO (9262) -> LORET_69 (9277) CKT 1 (138/69kV)	66	LORET_69 (9277) to LORETTO (9262) CKT 2 (69/138kV)	114.37		100.81
LORETTO (9262) -> LORET_69 (9277) CKT 2 (138/69kV)	64	LORET_69 (9277) to LORETTO (9262) CKT 1 (69/138kV)	112.89		
MARIDEL (9199) -> OCEANCTY (9204) CKT 1 (69kV)	116	BISHOP (9174) to WORCESTR (9179) CKT 1 (138kV)		103.82	102.14
		WORCR_69 (9210) to WORCESTR (9179) CKT 1 (69/138kV)		103.83	102.15
NSEAF_69 (9021) -> TAYLOR (9024) CKT 1 (69kV)	64	SHARR_69 (9023) to SHARNGTN (9004) CKT 1 (69/138kV)		103.11	105.78
OAKHL_69 (9330) -> WATTSVIL (9333) CKT 1 (69kV)	91	PINEY_69 (9285) to PINEY138 (9264) CKT 1 (69/138kV)	100.53		
OCNBAY (9203) -> MARIDEL (9199) CKT 1 (69kV)	137	BISHOP (9174) to WORCESTR (9179) CKT 1 (138kV)		112.34	110.85
		WORCR_69 (9210) to WORCESTR (9179) CKT 1 (69/138kV)		112.34	110.85
OMAR (9182) -> BETHANY (9173) CKT 1 (138kV)	336	BISHOP (9174) to FRANKFRD (9175) CKT 1 (138kV)	101.40		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	109.49		
OMAR (9182) -> INDRV2&3 (9176) CKT 1 (138kV)	336	BETHANY (9173) to 138TH ST (9180) CKT 1 (138kV)		109.22	109.18

WORCR_69 (9210) -> BERLINTP (9186) CKT 1 (69kV)	95	OCNBAY (9203) to OCEANBAY (9177) CKT 1 (69/138kV)	103.17	102.95	102.96

Table 11 - Contingency Voltage Violations for 777 MW Total Injection at Bethany and Nelson

Bethany Injection 600 MW Windfarm and Nelson Injection 177 MW CCGT (Alternative 4)			Voltage Violations, per unit		
Voltage Violating Bus	**Violated Limit**	**Contingency Element**	Base Case	DP&L Generation Offset	DP&L Import Offset
CECIL138 (9388) (138kV)	1.1000	GLASGOW (8818) to CECIL138 (9388) CKT 1 (138kV)		1.1246	
FIVE PTS (9193) (69kV)	0.9000	IR4 (9219) to INDRIV4 (9171) CKT 1 (26/230kV)	0.8999		
		BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8937		
		FRANKFRD (9175) to INDRV2&3 (9176) CKT 1 (138kV)	0.8982		
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8863		
LEWES TP (9197) (69kV)	0.9000	BETHANY (9173) to OMAR (9182) CKT 1 (138kV)	0.8997		
		INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8924		
MIDWAY (9200) (69kV)	0.9000	INDRV2&3 (9176) to OMAR (9182) CKT 1 (138kV)	0.8990		

The first result to notice from the 777 MW total injection contingency analysis is that several of the base case violations originally observed are no longer present with the new injection at the Bethany and Nelson 138kV buses. Only thermal contingency violations on the Glasgow to Cecil 138kV branch and on the Worcestor to Berlin Tap 69kV branch were common to the base case and to both of the Bethany and Nelson combined injection scenarios. The overloads that occurred on these two branches were not significantly increased or decreased by the 777 MW total injection, therefore this injection has little impact on those two circuits. In addition, all of the voltage violations evident in the original base case contingency analysis have disappeared with the addition of the total injection at Bethany and Nelson. These observations are generally the same as those seen for alternative 1, with the wind farm injection at Bethany only.

Bethany and Nelson Injection to DP&L Generation

Despite alleviating several of the base case contingency violations, the combined injection at Bethany and Nelson did create several new contingent violations. A total of six transmission elements experienced new thermal overloads and one new bus voltage violation were observed during the contingency evaluation with the new Bethany and Nelson injection offset specifically by DP&L generation. The locations of the contingency overloaded elements are shown in Figure 25, with elements experiencing overloads for one contingency highlighted dark blue, and elements experiencing overloads for two contingencies highlighted slate blue. All contingent overloads occurred on elements electrically close to the Bethany injection point, with the exception of the Glasgow to Cecil 138kV circuit, located much farther to the North.

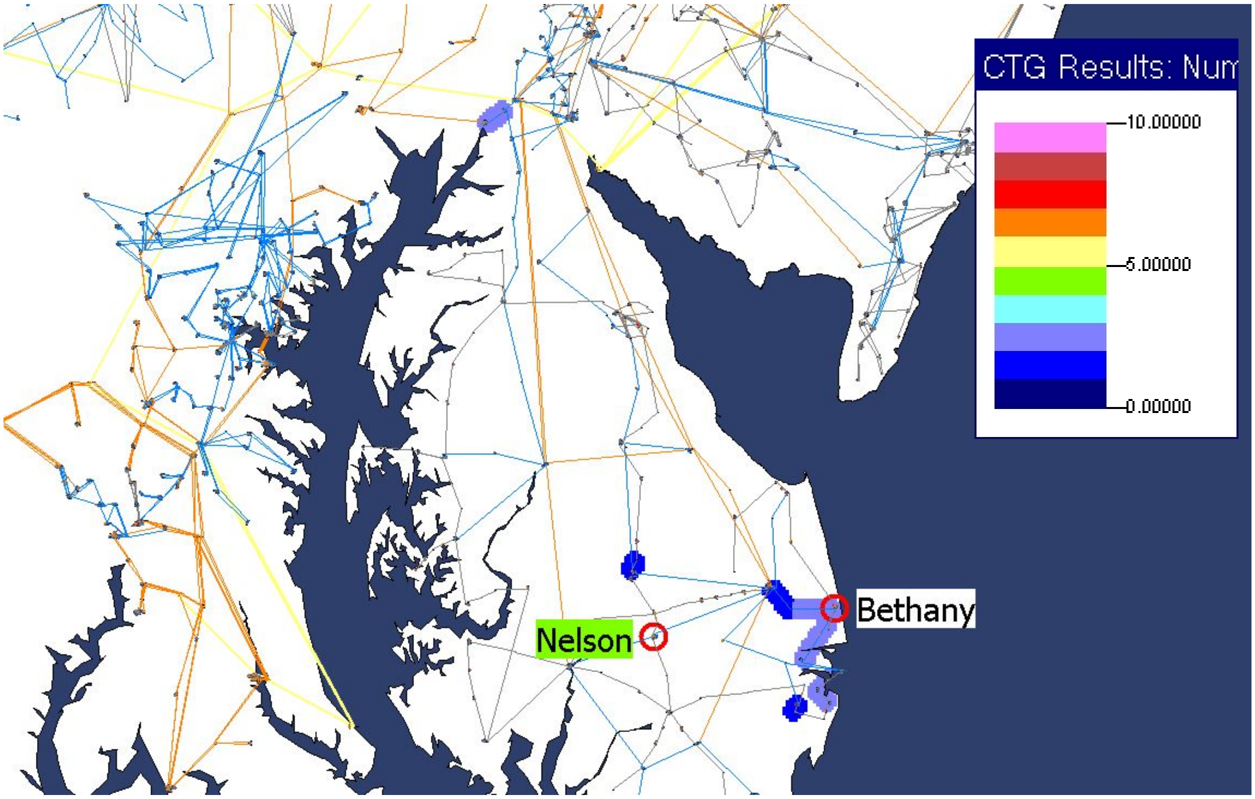

Figure 25 - Highlighting Transmission Elements Experiencing Contingency Overloads – Bethany and Nelson to DP&L

The largest contingent overload of 116.09% occurs on the Glasgow to Cecil 138kV circuit, but that is nearly identical to the contingent overload on that circuit in the base case results. Thus the Bethany and Nelson injection has little impact on this overload. The highest new contingent overload due specifically to the new injection at Bethany and Nelson offset by DP&L generation is 113.87% on the Bethany to Omar 138kV circuit. Two other 138kV circuits experience contingency overloads, those being Bethany to 138th Street and Omar to Indian River. It is possible that circuit upgrades or contingent remedial actions would need to be determined regarding these two circuits for the Bethany injection point, as they will carry a significant amount of the new power injection.

The remaining new contingency violations are on 69kV elements in the nearby 69kV system. Since the 69kV system between Bethany and Indian River has no large-scale connected generation, the new overloads on the 69kV in that region are due strictly to "pass through" of power from the new Bethany 138kV injection. This means that a certain amount of the injected power flows down to the 69kV system at Bethany, and travels across the 69kV network and back out onto the 138kV and 230kV network via connections at Indian River. The contingency violations on the 69kV system indicate that circuit upgrades or remedial actions may be necessary with the addition of the 600 MW wind farm injection at Bethany.

The only contingent voltage violation that occurs with the injection of 600 MW at Bethany and 177 MW at Nelson, offset by DP&L generation, is a high voltage violation at the Cecil 138kV bus during the contingency outage of the Glasgow to Cecil 138kV branch. This high voltage situation may or may not be of serious consequence, and may be handled with remedial actions by DP&L should the contingency occur.

There are a couple of notable differences between the combined dispatch of Bethany and Nelson and the Bethany wind farm by itself. First, the contingency overload on the NSEAF to Taylor 69kV branch is present only in the combined dispatch case. This indicates that this contingency overload is due to the addition of the 177 MW dispatch at Nelson to the Bethany 600 MW injection. The second difference is that the Worcestor to Ocean Bay 69kV branch and Ocean City to Culver 69kV contingent overloads are no longer present with the addition of the 177 MW Nelson injection to the Bethany 600 MW injection. The rest of the contingent violations that occurred with the Bethany 600 MW injection only also appear with the inclusion of the 177 MW at Nelson, with minor variations in the percentage of contingent overload on those elements.

Bethany Injection to DP&L Import Offset

The results of the Bethany and Nelson total injection offset by reducing DP&L imports are very similar to the DP&L generation offset scenario. There are three transmission elements during the contingency analysis in this scenario that were also contingency overloaded elements in the base case prior to the new injection. There were also seven additional transmission elements that experienced contingency overloads under this scenario that were not overloaded in the base case contingency analysis. There are no contingent voltage violations that occur under the DP&L import offset scenario. The locations of the contingency overloaded elements are shown in Figure 26, with elements experiencing overloads for one contingency highlighted dark blue, for two contingencies highlighted slate blue, for three contingencies highlighted light blue, and for four contingencies highlighted light green. All contingent overloads occurred on elements electrically close to the Bethany injection point, with the exception of the Glasgow to Cecil 138kV circuit and Edgemoor to DUP-EM 69kV circuit, located much farther to the North.

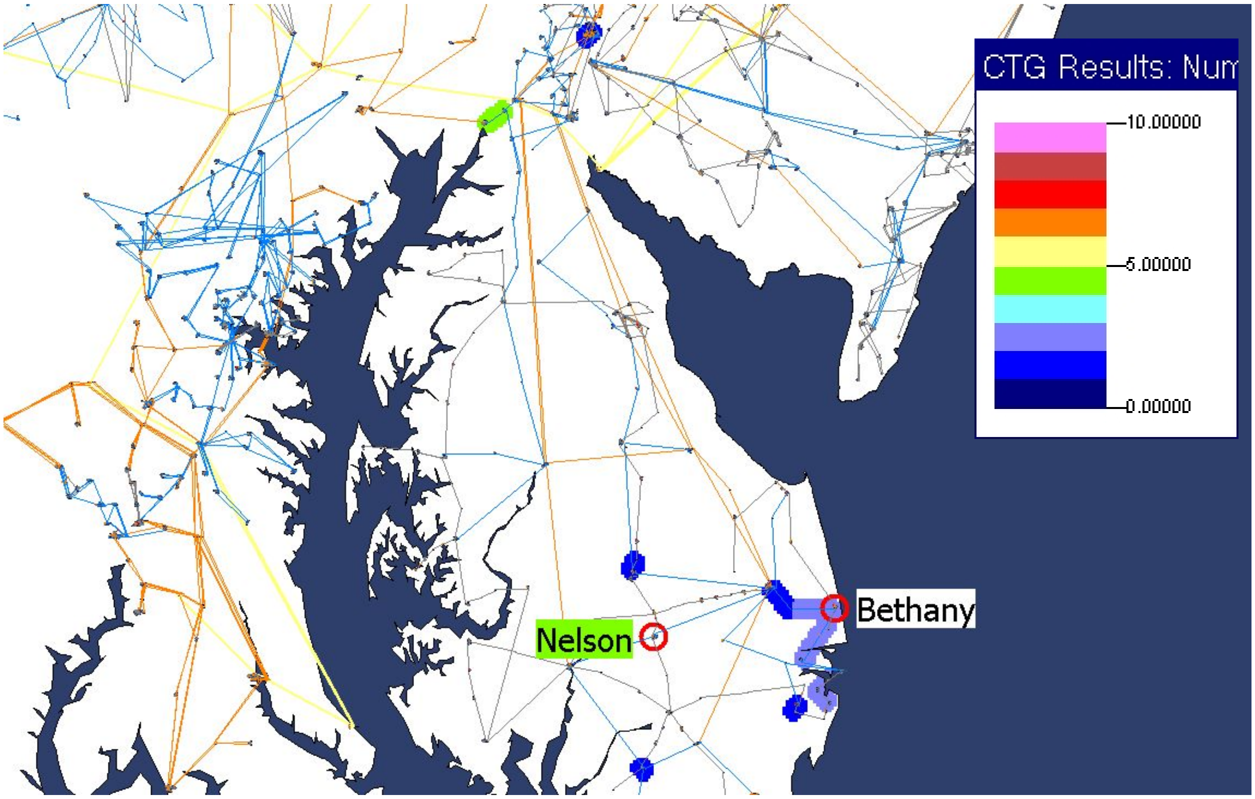

Figure 26 - Highlighting Transmission Elements Experiencing Contingency Overloads – Bethany and Nelson to PJM

The largest contingent overload of 116.08% occurred again on the Glasgow to Cecil 138kV circuit, which is approximately the same overload as the circuit experienced in the base case analysis. The highest new contingent overload of 113.86% occurs on the Bethany to Omar 138kV circuit, nearly identical to the DP&L generation offset results. The other two 138kV circuits experiencing contingent overloads are also similarly contingent overloaded in both offset scenarios. This is not unexpected, as the 138kV system out of Bethany and Nelson will carry a bulk of the new injection whether offsetting DP&L generation or out of area generation.

When comparing the results of the DP&L generation offset analysis to the DP&L import offset analysis, there is only one contingent violation that is unique only to the scenario of the DP&L import offset. This thermal violation occurs on the Edgemoor to DUP-EM 69kV branch during the contingency outage of the Clay to Edgemoor 230kV circuit. All other contingent overloads in this scenario occurred in either the base case contingency analysis or in the DP&L generation offset contingency analysis.

When comparing the results of the Bethany and Nelson injection to the injection at Bethany only for the sink of generation by reducing DP&L imports, it is again observed that the contingency results are very similar. The only additional contingency violations observed were the Edgemoor to DUP-EM 69kV branch, a fourth contingency violation on the Glasgow to Cecil 138kV circuit, and a contingent overload on the NSEAF to Taylor 69kV circuit. Another notable difference is the improvement of the contingency overloads on the Loretto 69kV to 138kV transformers, which were reduced to at or just below their contingency limit with the inclusion of the 177 MW injection at Nelson.

Summary

The general conclusions from both generation offset scenarios for the 600 MW wind farm at the Bethany 138kV substation and 177 MW CCGT at the Nelson 138kV substation are that the total injection does help alleviate most base case contingency violations, but at the same time introduces new contingent violations on other circuits. DP&L would need to assess these new violation scenarios more thoroughly, and determine courses of action related to each potential contingent overload. The new total injection does, however, show an improvement of contingent voltage problems with the inclusion of adequate voltage support with the injection.

A conclusion can also be drawn that the addition of the 177 MW CCGT at Nelson does not have a large impact on the original results previously seen for the Bethany wind farm injection by itself. The Nelson injection resulted in a few new contingent violations, but none that were significant. The new injection also helped reduce some of the original contingent violations caused by the Bethany wind farm injection only, but again these impacts were not significant improvements. Overall the inclusion of the 177 MW CCGT with the Bethany wind farm will provide some additional generation beyond the 600 MW wind farm at Bethany for DP&L, with some tradeoff in improving contingent violations resulting from the Bethany injection by itself, but also causing some additional minor contingency overloads not otherwise encountered.

The greatest benefit of the CCGT at Nelson for this alternative would come from the voltage support it could provide if additional voltage support devices are not included with the wind farm at Bethany. In this analysis, ample voltage support was assumed at the Bethany wind farm. Given that wind farm voltage support is minimal without external voltage support devices, the CCGT would be one way to provide the external VAR support necessary. Additionally, the Nelson CCGT appears that it could be a good alternative for replacing the voltage support currently provided by the Indian River 1 and 2 units, if they are in fact retired. Including the voltage support from the CCGT unit at Nelson in the scenario of the outage of the Indian River 4 unit showed the largest voltage drop of 2.51kV at the Cartanza 230kV bus. This is nearly identical to the original base case solution for the Indian River 4 unit outage with Indian River 1 and 2 still in place. This seems to suggest that the CCGT at Nelson may be a suitable steady state voltage reliability replacement for the retirement of Indian River 1 and 2.

Conclusions

The simulations reveal that the base case DP&L conditions represented in the 2011 summer peak time frame are subject to a small number of contingent violations, prior to any additional generation considerations in the area. These base case contingent violations occurred on the 138kV and 69kV system elements within DP&L. The five critical contingencies involving the three 138kV to 69kV pathways between Bethany and Indian River resulted in unsolvable load flow conditions in all studied generation alternative scenarios. These five contingencies would need to be addressed operationally by DP&L regardless of which generation alternative was in place.

Alternative generation scenarios involving the addition of generation at the Indian River 230kV substation or at the Red Lion 230kV substation (alternative 2 and 3, respectively) showed very little affect on the base case contingent violations, nor did either result in any significant new contingent violations. In the case of the Red Lion injection, the reason for little affect on the base case contingent results is two-fold. First, the injection is relatively small at 177 MW, compared to the 600 MW studied at Indian River and Bethany. Second, the location of Red Lion is in the Northern region of the DP&L area, which is far removed from the base case contingent violations, which primarily occur in the Southern DP&L region. In the case of the Indian River injection, the most likely reason it has little affect on the base case contingency violations is due to the fact that the new generation was connected directly to the 230kV system. Most of the power generated from the Indian River connection will remain on the 230kV system. A smaller amount of the injected power will travel down to the 138kV and 69kV systems. The only noticeable larger scale affect the Indian River injection had on the base case contingency violations was on the Indian River 138kV to 230kV transformers, which may indicate that transformer upgrades or additional transformers may be necessary at Indian River to support the new injection at the 230kV level. Overall for these two alternatives, the results of this specific n-1 contingency analysis seem to indicate that either of these two generation alternatives could be added to the DP&L system without significantly altering the thermal system security concerns already in place in the base case conditions. From a steady state voltage perspective, the Red Lion injection will have little impact on the voltage reliability in the south, but the Indian River IGCC plant could have substantial voltage reliability benefit, especially if the Indian River 1 and 2 units are ever retired.

Both alternatives involving the injection of new generation at the Bethany 138kV substation (alternatives 1 and 4) offered mixed results from the contingency analysis. The injection of power at Bethany did help improve or eliminate many of the base case contingency overloads that occurred prior to the inclusion of the new generation. However, the new generation also resulted in new contingency violations occurring that had not been present in the base case conditions. The addition of the 177 MW CCGT at Nelson to the Bethany 600 MW wind farm injection in alternative 4 did not seem to greatly alter the results of the contingency analysis compared to the injection of 600 MW at Bethany by itself. This would seem to indicate that most of the changes in the contingency analysis results from the base case are due to the 600 MW injection at Bethany. Alternative 1 and 4 may be of more concern in terms of evaluating system security, as the difference in contingency violations that occur between the base case and the Bethany injection scenarios would likely require more detailed individual contingency assessment to determine the changes to operational procedure that may be required. This conclusion should by no means imply that alternatives 1 and 4 are not as desirable as alternatives 2 and 3, but rather it just points out that the contingent violations may shift the focus of the operating procedures to different system elements than would otherwise be the focus if the new generation is not added at Bethany. From a steady state voltage point of view, the CCGT at Nelson would provide additional voltage reliability in the Southern DP&L region, and would help maintain the voltage reliability in the region if Indian River 1 and 2 were retired.

One final note worth mentioning is that none of these results take generation costs or ISO dispatch into account. If any of the studied n-1 contingencies are included in the PJM security constrained generation dispatch algorithms, then it is possible that any of the generation sources from the four alternatives could find themselves curtailed to a reduced dispatch by the PJM market. Commonly generator output is curtailed by a security constrained dispatch if the generation costs are higher than other generation or if it is determined that the new generation needs to reduce output in order to help maintain potential contingent flows within acceptable limits. Of course, it could also be determined by the security constrained dispatch that other previously existing generation is better to reduce than the new generation alternatives, allowing the new generation to dispatch to full capacity. The only way to know for sure how the new generation alternatives would be impacted by the contingency violations from the market point of view would be to perform a security constrained optimal power flow analysis on the PJM system (including DP&L.) This type of analysis requires a significant amount of additional information, including but not limited to reasonable generator bid or marginal cost information, the defined set of monitored elements and specific contingencies used by PJM in their market dispatch calculations, and so on. However, the general analysis performed in this study is certainly beneficial in providing insight into the contingency violations that exist during each of the new generation alternatives, and therefore may later be of concern to PJM when determining dispatch levels for the new generation.

Appendix A – Percentage of New Injection MW Picked Up by DP&L Generators (Output Reduction)

Number	Name	ID	Gen MW
9341	BAYVIEW1	1	0.25%
8973	CHRIST1	1	0.49%
8974	CHRIST2	1	0.51%
9298	CRISFLD1	1	0.27%
8978	DC CT6	1	2.56%
8977	DC CT7	1	2.56%
8879	DC1 NUG	1	0.65%
8882	DC10	1	0.43%
8880	DC2 NUG	1	0.65%
8881	DC3 NUG	1	1.80%
9006	DEMECNUG	1	2.05%
9380	EASTMUNI	1	0.65%
8886	EM10	1	0.37%
8883	EM3	3	1.60%
8884	EM4	4	4.26%
8885	EM5	5	10.15%
9370	GEN FOOD	1	0.31%
8965	GEN4	4	1.77%
8887	HR1	1	2.35%
8888	HR2	2	2.35%
8889	HR3	3	2.35%
8890	HR4	4	4.71%
8891	HR5	5	2.85%
8892	HR6	6	2.85%
8893	HR7	7	4.71%
8894	HR8	8	4.71%
9220	IR10	1	0.37%
9218	IR3	3	4.26%
9219	IR4	4	10.13%
9371	MR1	1	0.45%
9372	MR2	2	0.45%
9373	MR3	3	2.74%
9369	NORTHST	1	0.72%
9652	NRG_G1	2	1.46%
9653	NRG_G2	1	1.46%
9601	OH NUG1	1	2.13%
9602	OH NUG2	2	2.13%
9603	OH NUG3	3	2.13%
9604	OH NUG4	4	2.13%
9605	OH NUG5	5	2.13%
9606	OH NUG6	6	2.13%
9607	OH NUG7	7	2.13%
9350	TASLEY2G	1	0.57%
9124	VN10	1	0.35%
9123	VN8	8	3.68%
8968	WEST 1	1	0.29%